WASHINGTON COUNTY

PUBLIC NOTICE
ISSUANCE OF DRAFT PERMIT TO INSTALL
SUBJECT TO PREVENTION OF SIGNIFICANT DETERIORATION REVIEW
FOR DUKE ENERGY WASHINGTON, LLC

Public Notice is hereby given that the Staff of the Ohio Environmental Protection Agency (EPA) has recommended to the Director that the Ohio EPA issue a draft action of a Permit to Install (PTI) to Duke Energy Washington, LLC in Washington County, Ohio. The draft was issued on October 19, 2000.

This draft permit proposes to allow an allowable emission rate from the operation of natural gas fired combined cycle turbines at the facility. The new allowable emissions are, in tons per year:

Particulate Matter less than 10 microns (PM10)	**207.3**
Sulfur Dioxides (SO2)	**113.1**
Carbon Monoxides (CO)	**909**
Nitrogen Oxides (NOx)	**316.3**
Volatile Organic Compounds (VOC)	**126.4**
Sulfuric Acid Mist (H2SO4)	**17.2**

This facility is subject to the applicable provisions of the Prevention of Significant Deterioration (PSD) regulations as promulgated by U.S. EPA (40 CFR 52.21).

The maximum ambient increment allowed by U.S. EPA for PM10 is 30 micrograms/cubic meter on a 24-hour average, and is 17 micrograms/cubic meter on an annual average; for NOx, it is 25 micrograms/cubic meter on an annual average; for SO2, it is 512 micrograms/cubic meter on a 3-hour average, is 91 micrograms/cubic meter on a 24-hour average, and is 20 micrograms/cubic meter on an annual average. The Ohio EPA allows PSD sources to consume less than one half the available increment.

This facility has demonstrated that the impacts from the new sources are less than the PSD significant impact increments of 1 micrograms/cubic meter on a 24-hour average, 5 micrograms/cubic meter on an annual average for PM10; 2000 micrograms/cubic meter on a 1-hour average, 500 micrograms/cubic meter on a 8-hour average for CO; 1 micrograms/cubic meter on an annual average for NOx; 25 micrograms/cubic meter on a 3-hour average, 5 micrograms/cubic meter on a 24-hour average, and 1 micrograms/cubic meter on an annual average for SO2. Therefore, the impacts are insignificant and increment modeling is not required. Based on this analysis, the project complies with the PSD increment requirements.

A draft action (permit no. 06-06167) was issued on October 19, 2000. Within 30 days from the date of this notice, any interested party may submit comments or request a public hearing. Comments are to be sent to Zach Hamlin, Ohio Environmental Protection Agency, Southeast District Office, 2195 Front Street, Logan, Ohio, 43138.

Further information concerning this application, which is available for public inspection, may be secured from Ohio Environmental Protection Agency, Southeast District Office at the above address during normal business hours. Telephone number: (740) 385-8501.

STAFF DRAFT ACTION DETERMINATION
FOR THE APPLICATION OF
WASHINGTON ENERGY FACILITY - DUKE ENERGY WASHINGTON, LLC'S
PREVENTION OF SIGNIFICANT DETERIORATION (PSD)
AIR PERMIT TO INSTALL NO. 06-6167 FOR
TWO COMBINED-CYCLE 170 MEGAWATTS NATURAL GAS FIRED
GENERAL ELECTRIC 7FA TURBINES TO BE LOCATED IN
WATERFORD TOWNSHIP IN WASHINGTON, COUNTY, OHIO

October 19, 2000

Ohio Environmental Protection Agency
Division of Air Pollution Control
122 South Front Street
Columbus, Ohio 43215

Facility Description

Duke Energy Washington, LLC is proposing to build and operate two combined-cycle 170 megawatts gas fired General Electric 7FA turbines burning natural gas, two heat recovery steam generators (HRSG) augmented with supplementary natural gas fired duct burners, a reheat condensing steam turbine, a 12-cell wet cooling tower, a gas-fired auxiliary boiler, a 600 kilowatt (KW) back-up diesel generator, and a small diesel firewater pump. Total facility output is about 520 MW without duct firing, or 620 MW with duct firing and inlet chilling. This facility is to be located in Waterford Township, Washington, County, Ohio.

New Source Review (NSR)/PSD Applicability

The Washington Energy Facility is classified as a "major" stationary source because the potential emissions exceed the 250 tons per year of one of the criteria pollutants (NO_x) and is also one of the 28 source categories because it will generate steam and therefore triggers the 100 tons per year threshold level in an attainment area and thus be classified as a major source under the federal Prevention of Significant Deterioration (PSD) program.

The new installation "Washington Energy Facility" is classified as a "major modification" of a stationary source because the potential emissions exceed the significant emission rate levels for particulate matter(PM), particulate matter less than 10 microns (PM_{10}), sulfur dioxides (SO_2), ozone [as Volatile Organic Compound (VOC)] and carbon monoxide (CO).

Sulfuric acid mist (H_2SO_4) will be emitted as a PSD regulated non-criteria pollutant.

Washington, County, Ohio where the proposed installation will be built is designated is an attainment area for all pollutants under the Clean Air Act Amendments of 1990. In this case, since the facility is classified as a "major" stationary source for PSD, and then any addition that would emit a regulated pollutant at a rate in excess of the significance levels would require the facility to perform a PSD analysis for those pollutants.

Table 1 shows the emissions from the proposed modification.

Table 1

Pollutant	Tons/Year	Significant Level
Nitrogen Oxides (NO_2)	316.3	40
Sulfur Dioxide (SO_2)	113.1	40
Particulate Matter <10 (PM_{10})	207.3	15
Carbon Monoxide (CO)	909	100
Volatile Organic Compounds(VOC)	126.4	40
Sulfuric Acid Mist (H_2SO_4)	17.2	7

Based upon the above information, PSD review is required for NO_x, SO_2, PM_{10}, CO, VOC, and H_2SO_4.

New Source Performance Standards (NSPS) Applicability

Each of the combined cycle gas fired combustion turbines/HRSG augmented with supplementary natural gas fired duct burners is subject to 40 CFR 60 Subpart GG, "Standards of Performance for Stationary Gas Turbines" and 40 CFR 60 Subpart Da, "Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978".

The auxiliary boiler (46.6 mmBTU/hr on an HHV) is subject to 40 CFR 60 Subpart Dc, "Standards of Performance for Small Industrial/Comerica/Institutional Steam Generating Units".

The Stationary Gas Turbine NSPS applies to emissions for NO_x and SO_2. The emission standard for NO_x emissions applicable to the combustion turbine [from the equation in 40 CFR 60.332(a)(1)] is 0.0075 percent by volume (75 ppmv) at 15 percent oxygen on a dry basis. This standard is applicable to either fuel oil or natural gas combustion. The emission standard for SO_2 emissions applicable to the combustion turbine [from the equation in 40 CFR 60.333(b)] is 0.015 percent by volume (150 ppmv) at 15 percent oxygen on a dry basis. SO_2 emissions from combustion turbines are further limited by 40 CFR 60.333(b) which prohibits burning fuel that contains sulfur in excess of 0.8 percent by weight.

National Emission Standards for Hazardous Air Pollutants (NESHAP) Part 63, 112(g) and Ohio Administrative Code (OAC) rule 3745-31-28 Applicability

Currently there are no standards that have been promulgated for this project. If no standard has been promulgated, then the project is evaluated based upon the amount of Hazardous Air Pollutants emitted. If over the threshold levels, then a Maximum Achievable Control Technology (MACT) determination must be submitted for review.

The duct burners associated with this project are exempt from this applicability due to these units meeting the definition of electric steam generating unit.

The Washington Energy Facility will be accepting HAP emission restrictions to levels below to avoid submitting a MACT determination.

Control Technology Review

The new installation " Washington Energy Facility" is subject to PSD regulations which mandates a case-by-case Best Available Control Technology (BACT) analysis be performed for the following pollutant: NO_x, SO_2, PM_{10}, CO, VOC, and H_2SO_4. The application used a "top-down" approach to determine an appropriate level of

control.

Site Description/Air Quality Designations

The new installation "Washington Energy Facility" has proposed to build and operate two combined-cycle 170 megawatts gas fired General Electric 7FA turbines burning natural gas, two heat recovery steam generators (HRSG) augmented with supplementary natural gas fired duct burners, a reheat condensing steam turbine, a 12-cell wet cooling tower, a gas-fired auxiliary boiler, a 600 kilowatt (KW) back-up diesel generator, and a small diesel firewater pump to be located in Waterford Township, Washington, County, Ohio. Under Section 107 of the Clean Air Act as of June 24, 1992, this area was classified as attainment for all of the criteria pollutants, i.e., total suspended particulates, particulate matter less than 10 microns, sulfur dioxide, nitrogen oxides, carbon monoxide, lead, and volatile organic compounds (ozone).

BACT Review

As part of the application for any emissions unit regulated under the PSD requirements, as analysis must be conducted that demonstrates that Best Available Control Technology (BACT) will be employed. In this case, the BACT analysis was conducted for NO_x, SO_2, PM_{10}, CO, VOC, and H_2SO_4. For the purposes of performing a BACT analysis, the above emissions listed in Table 1 are described in the following sections.

Control of Nitrogen Oxides

Combustion Turbines

The new installation "Washington Energy Facility" looked at the following control technologies for nitrogen oxides:

- Dry Low NO_x-9 (DLN-9) - (Front end control)
- Selective Catalytic Reduction - (Back end control)
- $SCONO_x$ - (Back end control)
- XONON catalytic (flame less)combustion - (Front end control)

Dry Low NO_x-9 (DLN-9) - (Front end control)

The rate of formation of thermal NO_x is a function of residence time and free oxygen, and is exponential with peak flame temperature. "Front end" NO_x control techniques are aimed at controlling one or more of these variables. The most efficient front end combustion controls for gas turbines include water or steam injection and dry low NO_x combustors. The addition of an inert diluent such as water or steam into the high temperature region of the flame controls NOx formation by quenching peak flame temperature. This technique can be operationally very hard on the turbine and combustors due to vibration and flame stability. Recent advances in the state of art have resulted in dry low NO_x combustors which limit peak flame temperature and excess oxygen with lean, pre-mix flames that achieve equal or better NO_x control without the addition of water or steam. The "Washington Energy Facility" will be using dry low NO_x combustors to control NO_x emissions emitted from the two 170MW gas fired turbines.

Selective Catalytic Reduction (SCR) - (Back end control)

In addition to the use of dry low NO_x combustors, Duke Energy Washington, LLC proposes to install SCR in the HRSG to control NO_x emissions from the combustion turbines. These are the most advanced control technologies currently available that have been demonstrated in practice to control NO_x emissions from

combined-cycle gas turbines greater than 100 MW in capacity.

SCR is an add-on control which utilizes the injection of ammonia (NH_3) into the exhaust gas stream, which then passes through a catalyst to convert the NO_x and NH_3 into nitrogen and water. The general chemical reactions are:

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O \text{ and}$$

$$2NO_2 + 4NH_3 + O_2 \rightarrow 3N_2 + 6H_2O$$

The reactions take place on the surface of a catalyst. The function of the catalyst is to effectively lower the activation energy of the NO_x decomposition reaction. Technical factors related to this technology include the catalyst reactor design, optimum operating temperature, sulfur content of the fuel, and design of the ammonia (NH_3) injection system.

An SCR system is composed of an ammonia storage tank, ammonia forwarding pumps and controls, an injection grid (system nozzles that spray ammonia into the exhaust gas ductwork), a reactor which contains the catalyst and instrumentation, and electronic controls. An injection grid disperses NH_3 in the flue gas upstream of the catalyst, and NH_3 and NO_x are reduced to N_2 and water in the catalyst reactor. This control techniques reduces both thermal NO_x and fuel NO_x in the exhaust streams.

The optimum operating temperature for a vanadium-titanium catalyst has been shown to be in the range of 550^o to 800 ^{o}F. In applications where heat recovery steam generation is used, SCR catalyst and ammonia injection grids are typically installed between tube bundles within the HRSG where the flue gas temperature remains with the required temperature range during base load operation.

The SCR process is also subject to catalyst deactivation over time. Catalyst deactivation occurs through two primary mechanisms: physical deactivation and chemical poisoning. Physical deactivation is generally the result either of prolonged exposure to excessive temperatures or masking of the catalyst due to entrainment of particulate from ambient air or internal contaminants. Chemical poisoning is caused by the irreversible reaction of the catalyst with a contaminant in the gas stream and is a permanent conditions. Catalyst suppliers typically only guarantee a 3-year lifetime to very low emission level, high performance catalyst systems.

SCR manufacturers typically estimate 20 parts per million (ppm) or more of unreacted ammonia emissions (ammonia slip) when operating at very high efficiency levels. The ammonia is injected into the exhaust stream in excess of stoichiometric amounts to achieve maximum conversion of NO_x. Although this reduces NO_x emissions substantially, a significant quantity of ammonia is not reacted, passes through the SCR reactor and is exhausted to the atmosphere. Thus, there is a clear emissions trade-off between NO_x and ammonia in NO_x reduction applications of SCR.

The firing of diesel fuel and other sulfur-bearing fuels produces SO_3 which may oxidize to sulfite (SO_2) in the catalyst reactor. This SO_3 reacts with ammonia in the exhaust to form ammonium salts, resulting in additional particulate matter emissions. The SO_3 can also form H_2SO_4 in the exhaust, resulting in acid mist emissions. The conversion of SO_3 to H_2SO_4 is directly proportional to the NO_x reduction of the catalyst. Therefore, application of an SCR will increase emissions of other pollutants.

In summary, BACT is proposed to be a NO_x emission rate of 3.5 ppmvd at 15 percent O_2 when firing natural gas utilizing both the state-of-the-art GE dry low NO_x system and SCR to achieve at all operating conditions requested.

$SCONO_x$ - (Back end control)

An emerging technology called **$SCONO_x$**, offers the promise of reducing combined-cycle NO_x emissions to values less than 3 ppm. EPA on July 2, 1997 indicated that $SCONO_x$ as a back end catalyst which operates without ammonia has been demonstrated in practice as Lowest Achievable Emission Rate (LAER) as part of a Non attainment Review permit analysis in California on a 23 MW combined-cycle turbine installation with NO_x emissions at 2-2.5 ppm. In December, 1999, EPA Region I issued a letter to the States covered by Region I stating that his technology is considered technically feasible.

The $SCONO_x$ system uses an oxidation/absorption/regeneration cycle across a catalyst bed to achieve back end reductions of NO_x. Unlike SCR, the system does not require ammonia as reagent and involves parallel catalyst beds that are alternately taken off-line for regeneration through means of mechanical dampers.

According to Goal Line, the $SCONO_x^{TM}$ catalyst works by simultaneously oxidizing CO to CO_2, NO to NO_2, and then absorbing NO_2. The NO_2 is absorbed into a potassium carbonate catalyst coating as KNO_2 and KNO_3. When a catalyst module begins to become "loaded" with potassium nitrates and nitrates, it is taken off-line and isolated from the flue gas stream with mechanical campers for regeneration.

Once the module has been isolated from the oxygen rich turbine exhaust, natural gas is used to generate hydrogen gas. An absence of oxygen is necessary to retain the reducing properties necessary for regeneration. It should be noted that four percent is about the lower flammability limit for hydrogen, so it is important that piping and air seals around dampers do not leak. Hydrogen reacts with potassium nitrites and nitrates during regeneration to form H_2O and N_2 that is emitted from the stack.

$SCONO_x^{TM}$ is an emerging and very new technology. According to Goal Line, the first generation system (Mod 1) was based on a moving hood design that was used for proof of concept. This research led to the development of a second generation prototype (Mod 2) which has operated for over a year on a 23 MW General Electric LM 2500 turbine at the Federal facility operated by Goal Line's parent, Sunlaw Energy. A June 1999 newsletter from Goal Line announced that on May 29, an authority to construct was issued to the PG&E Generating La Paloma Project. The La Paloma FDOC states "Currently, it is uncertain, due to commercial availability issues, if $SCONO_x^{TM}$ will be installed on the fourth gas turbine.... The availability of $SCONO_x^{TM}$ for this project is contingent on ABB's ability to scale up and test the $SCONO_x^{TM}$ system in a time period consistent with La Paloma's schedule." This is an affirmative determination that $SCONO_x^{TM}$ is not yet ready for widespread application to 170 MW turbines.

$SCONO_x^{TM}$ catalyst is subject to the same fouling or masking degradation that is experienced by any catalyst operating in a turbine exhaust stream. Trace impurities either ingested from ambient air or internal sources gradually accumulate on the surface of the catalyst, eventually masking or poisoning active catalyst sites over time. This is why catalyst performance is known to degrade or "age" over time. As one example, a catalyst system operating on a similar size cogeneration unit at MIT in Cambridge, Massachusetts, experienced total catalyst failure after only several hundred hours of oil fired operation. It turned out that a trace element contained in an oil additive being supplied by the turbine manufacturer was discovered to be an aggressive catalyst poison. In an event, it is well demonstrated that all catalysts begin life at their highest level of reactivity, resulting in very low emissions when first installed. Goal Line reports that they have had to take periodic outages to wash the catalyst; apparently SO_2 present in natural gas is sufficient to mask the active catalyst sites. Goal Line has developed an SO_2 "guard bed" called $SCOSO_x$ to be installed on future systems such as La Paloma, but this component is not fully proven. As stated previously, catalyst aging is also experienced with conventional SCR catalysts; however, with these systems the operating experience exists to confidently predict

catalyst life and catalyst replacement cost.

Another area of concern is that the SCONO$_x$™ process is dependent on numerous hot side dampers and gas seals that must cycle every 10-15 minutes. According to Goal Line's literature, at the scale of the Federal facility, this involves approximately eight mechanical dampers cycling about 4 times per hour, or 32 damper movements per hour. At ten times the scale, an equivalent system for the Project would involve about one damper movement every ten seconds, 8,760 hours per year. While further research and development (R&D) may be done during scale up at La Paloma in an effort to reduce the number of moving parts, the SCONO$_x$™ system requires many mechanical linkages, activators, and damper seals which must operate reliably with a hostile flue gas environment. This, in combination with lack of long-term demonstration and the specter of a 10:1 scale up results in associated concerns with long-term availability. The La Paloma beta test will serve as a valuable R&D process to demonstrate that SCONO$_x$™ can be scaled-up and eventually be guaranteed commercially for a project such as Washington Energy Facility also provide the CEM data to determine if a large scale SCONO$_x$™ application can meet 2-2.5 ppm NO$_x$ on a continuous basis.

Commercial Availability

SCONO$_x$™ does not represent a commercially mature control technology for application to the Washington Energy Facility. On December 1, 1999 ABB Alstrom Power issued a press release making a commercial offering for SCONO™ on combined-cycle turbines. In order for the Washington Energy Facility to obtain the financing needed to construct this project, Goal Line or its licensee would typically have to post performance bonds, and would have to provide meaningful financial guarantees for performance and long-term system availability, including remedies and liquidated damages. Further, the unknowns associated with any pollution control system which is the first of its kind, and which has no long-term company or operating history, represents a level of risk that would alter the ability to reasonably finance the project. In summary, the Washington Energy Facility could not practically be financed and built if SCONO$_x$™ were required for emissions control. Although there are several technical feasibility concerns with this technology, an economic analysis was conducted for completeness.

Economic Evaluation

While SCONO$_x$™ may be considered a commercially available control technology for the Washington Energy Facility, it is not a cost-effective technology. An economic analysis of the SCONO$_x$™ technology was conducted. The cost spread sheets are included in Appendix C. Budget pricing for SCONO$_x$™ was provided by ABB. Costs for a SCOSO$_x$ guard bed and a hydrogen generation system (both necessary to make SCONO$_x$™ work) were included in the estimate. Since a SCONO$_x$™ system of this scale has never been attempted to date, the direct installation contingency cost was increased from 3 percent to 10 percent to address the greater level of uncertainty of the installation cost estimate.

Based on EPA cost factors this represents a total capital investment of greater than $15 million per turbine, or $30 million total. This represents a tremendous capital investment, particularly for an unproven, first of a kind system. In terms of projected operating cost, SCONO$_x$™ does not require ammonia and associated costs, however it still incurs costs due to system pressure drop and periodic catalyst replacement. The largest potential cost to an around the clock merchant power plant is the tremendous financial losses that would result from periodic shutdowns to wash the catalyst or unscheduled outages due to NO$_x$ control system masking or catastrophic failure. (The SCONO$_x$™ system in Vernon, California has to be routinely washed, which requires the unit to be off-line.) Such risks have been conservatively included in this economic analysis by assuming a control system availability of 98 percent, which is considered to be high for a first-of-a-kind scale up application.

Additionally, the value for operating contingency used in the spreadsheet was set at 10 percent of purchased equipment due to the unproven nature of the application. The estimated cost effectiveness of SCONO$_x$™ is about $55,000 per ton of NO$_x$ removed, and would not be cost effective for application to Washington Energy

Facility.

Environmental Impacts

The SCONO$_x$™ catalyst requires frequent washing as part of the regeneration process. Others developers (e.g., ANP) have identified that this process will require additional water and could potentially generate a hazardous waste (since the catalyst likely contains metals and other trace elements). Other adverse environmental impacts will likely result due to the increased fuel use for regeneration gas and additional steam production to regenerate the catalyst, a higher pressure drop than SCR, and reduced equipment efficiency resulting in higher emissions per kilowatt-hour. These considerations were not investigated in detail for this application since this technology is neither commercially available nor cost effective.

XONON catalytic (flame less)combustion - (Front end control)

Another emerging technology, **XONON**, is a catalytic (flameless) combustion technology which potentially capable of reducing gas turbine NO_x emissions to around 3-5 ppm. The XONON combustion technology is being sold commercially for certain (i.e., smaller) engine models and is not yet being offered for larger turbines, such as the 175 MW GE units proposed for the "Washington Energy Facility" new installation.

Unlike SCONO$_x$ or SCR, flameless combustion requires no down-steam clean up device, but rather prevents the formation of thermal NO_x during combustion of the fuel. This technique avoids the need for ammonia injection and avoids system efficiency losses due to catalyst back pressure. The **XONON** technology actually replaces the traditional diffusion or lean pre-mix combustion cans of the combustion turbine. Hence, this represents the only catalytic control technology that may be a reasonable retrofit to existing units.

Technical Analysis

According to literature provided by Catalytica, XONON™ combustors have reduced combustion turbine NO_x emissions to as low as 3 ppm in laboratory and pilot tests. Unlike SCONO$_x$™ or SCR, flameless combustion requires no down-stream clean up device, but rather prevents the formation of thermal NO_x during combustion of the fuel. This technique avoids the need for ammonia injection and avoids system efficiency losses due to catalyst back pressure. The XONON™ technology actually replaces the traditional diffusion or lean pre-mix combustion cans of the combustion turbine. Hence, this represents the only catalytic control technology that may be a reasonable retrofit to existing units.

In a typical combustor, fuel and air are burned at flame temperatures that may approach 2,700^{o}F. Since the NO_x formation rate is exponential with flame temperature above about 2,000^{o}F, thermal NO_x is formed within the combustors. The combustor exhaust is then diluted with cooling air to get the gas temperature below 2,400^{o}F, which is the upper temperature limit of the metal parts that make up the power turbine. With the XONON™ system, a fuel/air mixture is oxidized across several small catalyst beds to "burn" fuel at less than the flame temperature at which thermal NO_x formation begins. The XONON™ combustor does, however, utilize a partial flame downstream to complete the combustion process (burnout zone) and unavoidable small amounts of NO_x emissions are generated within this zone. Resulting emissions are being guaranteed at 5 ppm for some small turbine applications (less than 3 MW) and have been demonstrated as low as 3 ppm under test conditions. Like all catalysts, the XONON™ combustor catalyst performance can be expected to "age" with time. Unlike other catalysts, the XONON™ combustors can be easily changed out with a simple combustor replacement.

Commercial Availability

XONON™ does not currently represent an available control technology for the GE Frame 7 FA (or any other 170 MW class turbine). While XONON™ is being sold commercially for certain (mostly smaller) engine models, it is not yet offered for large industrial gas turbines. According to Catalytica, a joint venture agreement is in place with GE to eventually develop XONON™ as Original Equipment Manufacturer (OEM) and retrofit equipment for the entire GE turbine line. It is critical to note that General Electric does not currently offer an XONON™ combustor option for 7FA or any other large industrial turbine. Therefore, XONON™ does not represent an available control technology for this project.

Economic Analysis

Since the XONON™ combustors are not offered commercially for the turbines in the size range selected for the Washington Energy Facility and GE cannot provide cost data, an economic analysis could not be performed.

Duct Burners

SCR system represents BACT (and LAER) for the proposed project duct burners. NO_x emissions during duct firing will be controlled to 3.5 ppmvd.

Auxiliary Boiler

The proposed auxiliary boiler will incorporate a NO_x emission limit of 0.11 lb/MMBtu that will be achieved natural gas. Given the limited operation (500 hours per year) and the small capacity of this boiler (46.6 MMBtu/hr on an HHV basis) the installation of add on NO_x controls such as SCR, would not be cost effective. The firing of natural gas as the sole fuel represents BACT for the proposed auxiliary boiler.

Diesel Firewater Pump and Back-up Generator

EPA's Alternative Control Technology (ACT) document for reciprocating engines (EPA, 1996) lists back end techniques such as SCR as well as combustion control techniques such as ignition retard for NO_x control from diesel engines. The ACT concludes that add-on controls are not cost effective for "emergency diesel engines that operate less than 500 hours/year". Therefore, neither back endo nor combustion controls represent NO_x BACT for the diesel firewater pump and back-up diesel engine.

Control of Sulfur Dioxide

Combustion Turbines

SO_2 is emitted from the combustion turbines as a result of the oxidation of the sulfur in the fuel. The emissions of SO_2 from the firing of diesel fuel in the turbines will be proportional to the sulfur content of the fuel. Alternatives for controlling SO_2 from combustion sources include the use of various low sulfur fuel oils, such as diesel, and the addition of flue gas desulfurization (FDG) systems. These alternatives are more fully described below.

FDG is technology used to control SO_2 emitted from various combustion sources. An FGD system could be comprised of either a spray dryer which uses lime as a reagent followed by particulate control (baghouse or electrostatic precipitator) or a wet scrubber which uses limestone as a reagent. Installation of such systems is an established technology principally on coal-fired and high sulfur oil-fired steam-electric generating stations. FGD

systems have not been installed on combustion turbines because of technical and cost factors associated with treating large volumes of high temperature gas containing relatively low levels of SO_2. FDG systems typically operate at an inlet temperature of approximately 400 to 500^0F. In addition, FGD systems are not typically effective for streams with low SO_2 concentrations such as the flue gas stream from the proposed turbines. The concentration of SO_2 in the exhaust gas is the driving force for the reaction between SO_2 and the reagent. Therefore, removal efficiencies are significantly reduced with lower inlet concentrations of SO_2.

FGD systems also have energy and environmental impacts associated with their operation. A significant amount of energy is required to operate a FGD system due to the pressure drop over the scrubbers. There are also environmental impacts (e.g., bulk materials handling, wastewater discharges, and solid waste management) due to the disposal of the spent reagent and the high water use required for a wet scrubbing system.

For the technical reason and energy and environmental impacts presented above FGD systems are excluded from further consideration in the Project BACT analysis.

With the rejection of FGD and BACT for SO_2 the Project evaluated the use of low and very low sulfur fuels. The use of these fuels has established records of compliance when used in combustion equipment such as high efficiency combustion turbines and boilers. The NSPS established maximum allowable SO_2 emissions associated with combustion turbines requires either an SO_2 emissions limitation of 150 ppmvd at 15 percent O_2 or a maximum fuel content of 0.8 percent by weight (40 CFR 60, Subpart GG). Gas firing results in SO_2 emissions at approximately 1 ppmvd. Therefore, the very low SO_2 emission rate that results from the use of natural gas as the sole fuel represents BACT control for SO_2 emissions from the combustion turbine.

Duct Burners and Auxiliary Boiler

The duct burners and auxiliary boiler will exclusively fire pipeline quality natural gas with an annual average sulfur content of 2 grains per 100 scf. The most stringent method of control for SO_2 that has been demonstrated for combustion sources is limiting operation to pipeline quality natural gas only. The use of pipeline natural gas as the exclusive fuel is, therefore, representative of BACT for SO_2 from the gas turbines, duct burners and auxiliary boiler.

Diesel Firewater Pump and Back-up Generator

The only technique available for diesel engines that operate 500 hours or less pe year, is the use of low sulfur fuel. Therefore, the use of very low sulfur diesel fuel (0.05%) represents BACT for SO_2 from the diesel firewater pump and back-up diesel generator.

Control of Carbon Monoxide

Formation

Carbon monoxide (CO) is formed as a result of incomplete combustion of fuel. Control of CO is accomplished by providing adequate fuel residence time and high temperature in the combustion zone to ensure complete combustion. These control factors, however, also tend to result in increased emissions of NO_x. Conversely, a low NO_x emission rate achieved through flame temperature control (by water injection or dry lean pre-mix) can result in higher levels of CO emissions. Thus , a compromise is established whereby the flame temperature reduction is set to achieve the lowest NO_x emission rate possible while optimizing CO emission rates.

Gas Turbines - Ranking of Available Control Techniques

CO emissions from gas turbines are a function of oxygen availability (excess air), flame temperature, residence

time at flame temperature, combustion zone design, and turbulence. Alternative CO methods include exhaust gas back end controls such as catalytic oxidation, and front end methods such as combustion control wherein CO formation is suppressed within the combustors.

A review of CPA's RACT/BACT/LAER Clearinghouse indicates several levels of CO control, which may be achieved for natural gas-fired gas turbines. Potential emission levels and control technologies have been identified and ranked as follows:

- 2 to 6 ppm: CO oxidation catalyst
- 10 to 25 ppm: Combustion control for natural gas firing; oxidation catalyst for distillate oil firing
- 20 to 50 ppm: Combustion controls for distillate oil firing

A review of recent CO BACT determination in Region V indicates only one project that required the installation of an oxidation catalyst as LAER. These levels of control are evaluated in terms of Best Available Control Technology in the following sections.

- LAER: 2 to 6 ppm CO with Catalytic Oxidation

The most stringent Co control level available for gas turbines has been achieved with the use of an oxidation catalyst system, which can remove up to 90 percent of CO in the flue gas stream. According to the list of turbines in the RACT/BACT/LAER Clearinghouse with limits on CO, the lowest emission level listed in the Clearinghouse is 2.0 ppm for Mystic Station in Massachusetts. A CO oxidation catalyst is therefore concluded to represent the top control technology for CO control from natural gas-fired, combined-cycle turbines.

It should be noted that the makers SCONO$_x$™ provide a conventional oxidation catalyst as part of their scope of supply. This is necessary to make the absorption catalyst work, but is not unique or different from CO catalytic oxidation technology reviewed in this section.

Technical Analysis

As with SCR catalyst technology for NO_x control, oxidation catalyst systems seek to remove pollutants from turbine exhaust gas rather than limiting pollutant formation at the source. Unlike an SCR catalyst system, which requires the use of ammonia as a reducing agent, oxidation catalyst technology does not require the introduction of additional chemicals for the reaction to proceed. Rather, the oxidation of CO to CO_2 utilizes the excess air present in the turbine exhaust; the activation energy required for the reaction to proceed is lowered in the presence of the catalyst. Technical factors relating to this technology include the catalyst reactor design, optimum operating temperature, back-pressure loss to the system, catalyst life, and potential collateral increases in emissions of PM_{10}.

As with SCR, CO catalytic oxidation reactors operate in a relatively narrow temperature range. Optimum operating temperatures for base metal systems generally fall into the range of 700°F to 900°F. At lower temperatures, CO conversion efficiency falls off rapidly. Above 1,200°F, catalyst sintering may occur, thus causing permanent damage to the catalyst. For this reason, the CO catalyst is strategically placed within the HRSG for proper turbine exhaust lateral distribution (it is important to evenly distribute gas flow across the catalyst) and proper operating temperature at base load design conditions. Operation with duct burners on or off, at part load, or during start-up/shut-down can result in other than optimum temperatures and reduced control efficiency.

Catalyst systems are subject to loss of activity over time. Since the catalyst itself is the most costly part of the installation, the cost of catalyst replacement has been accounted for on an annualized basis. Depending on the actual installation, catalyst life may vary from the manufacturer's typical 3-year guarantee to a 5- to 6-year predicted life. Periodic testing of catalyst material is necessary to predict actual catalyst life for any given installation. The following economic analysis assumes that catalyst will be replaced every 3 years per vendor guarantee. This system would also be expected to control a small undetermined amount of hydrocarbon (VOC) emissions.

Environmental Analysis

A CO catalyst will also oxidize other species within the turbine exhaust. For example, sulfur in natural gas (fuel sulfur and mercaptans added as an odorant) is oxidized to gaseous SO_2 within the combustor, and a percentage is further oxidized to SO_3 across a CO catalyst (30% conversion is assumed). SO_3 will then be emitted and/or combined with water to form H_2 SO_4 (sulfuric acid mist) or ammonia to form ammonia salts (PM_{10}) in the exhaust stack. These sulfates condense in the gas stream or in the atmosphere as additional PM_{10} (and $PM_{2.5}$). Thus, an oxidation catalyst would reduce emissions of CO and to some extent VOC, but would increase emissions of PM_{10} and $PM_{2.5}$.

Economic Analysis

Capital and annual costs associated with installation of an oxidation catalyst system were obtained from Engelhard, a qualified vendor of catalyst control systems. Capital costs include the catalytic reactor, initial catalyst charge, freight, engineering and design, and installation. As shown in Appendix C. of the PSD application, the total purchased capital equipment cost per unit including installation is $1,430,654.

Since the catalyst is assumed to be replaced periodically (every 3 years), it was deducted from the initial purchase cost for purposes of determining annualized capital recovery. Catalyst replacement is treated separately in this analysis under operating costs.

Annual operating costs include routine inspection and maintenance, spent catalyst replacement, and lost cycle efficiency due to increased back-pressure. Annualized catalyst replacement cost was calculated based on a 3-year life, for an annualized cost of about $262,197. Estimated annualized costs total $599,774. At an estimated control efficiency of 80 percent to reduce CO from a maximum of 10 ppmvd to 2 ppmvd for the turbines only, the use of oxidation catalyst represents a maximum of 134.9 tons CO removed per year for each gas turbine at a cost of $4,400 per ton of CO controlled.

For the turbines and duct burners combined, the control efficiency to reduce CO from a maximum of 14.2 ppmvd to 2.8 ppmvd is 80 percent. This represents a maximum of 199.5 tons of CO removed, resulting in an average cost effectiveness of more than $3,000 per ton.

Since the duct burners will be limited to 4,500 hours per year, the incremental cost effectiveness of controlling CO emissions from the duct burners was evaluated. At a removal efficiency of 80 percent (27 ppm to 5.8 ppm), 64.6 tons per year will be removed at a cost of about $9,300 per ton.

Based on the high cost for controlling CO emissions for the turbines alone (<$4,000 per ton) and the incremental cost for controlling the duct burners proposed CO emission limit for the duct burners (>$9,000 per ton) an oxidation catalyst as determined not to be cost effective for this project.

Summary

The use of an oxidation catalyst to control emissions of CO from the turbines would result in collateral increases

in PM_{10} (and $PM_{2.5}$) emissions, is not cost effective, and therefore does not represent BACT for the Project. The next best level of control, for the turbine generators with duct firing is 10 ppmvd without duct burning using combustion control and is concluded to represent BACT for this facility. During duct firing, BACT for the project will be 14.2 ppmvd. The resulting emission level results in modeled impacts (presented elsewhere in this application) which are well below EPA's significance levels for the 1- and 8-hour CO NAAQS.

Duct Burners

Information received from the vendor is that duct burners will increase the CO emissions. This level of emissions was evaluated separately and in conjunction with the turbine emissions. For the turbines alone, the oxidation catalyst has already been shown to be not cost effective. Using the proposed CO emission limit for the duct burners alone results in an incremental cost effectiveness for the duct burners of more than $9,000 per ton. Based on a review of recent CO BACT determinations, this is not cost effectiveness. Therefore, good combustion control; therefore represents BACT for CO from the Project's duct burners.

Auxiliary Boiler

The auxiliary boiler will employ good combustion control for CO that has been determined to represent BACT for this source type.

Diesel Firewater Pump and Back-up Generator

Add on controls for CO emissions have never been applied to emergency diesel engines that operate less than 500 hours/year. Combustion control is concluded to represent BACT for the Washington Energy Facility firewater pump and back-up generator.

Control of Particulate Matter

Combustion Turbines, Duct Burners, Auxiliary Boiler, Diesel Fire Pump, and Back-up Generator

Emissions of PM and particulate matter less than PM_{10} from the combustion turbine result from inert solids contained in the fuel, unburned fuel hydrocarbons which agglomerate to form particles, and mineral matter in the water injected during diesel oil firing. All of the particulate matter emitted from the turbine is expected to be less than 10 micrometers in diameter.

When the New Source Performance Standard for Stationary Gas Turbines (40 CFR 60 Subpart GG) was promulgated in 1979, the EPA recognized that "particulate emissions from stationary gas turbines are minimal," and noted that particulate control devices are not typically installed on gas turbines and that the cost of installing a particulate control device is prohibitive. Performance standards for particulate control of stationary gas turbines were, therefore, not proposed or promulgated.

Natural gas is a clean burning fuel. Natural gas contains essentially no inert solids (ash). Clean fuels are required for combustion turbines in order to prevent damage to the turbine blades and other high precision turbine components. The installation of a particulate control device on a turbine firing clean fuels is considered to be impractical. Additionally, the small size of the particulates (100% 1μ, AP-42, Section 3.1) make add-on controls technically infeasible.

Given the high combustion efficiency of the turbines and the firing of clean fuels, PM emissions will be very low. PM/PM_{10} emissions from the Project will be less than 0.02 $lb/10^6$ Btu. The Project proposes the use of natural gas as the sole fuel and good combustion practices as BACT for particulate matter.

The most stringent particulate control method demonstrated for gas turbines, duct burners, small boilers or diesel engines is the use of low ash fuel (such as natural gas or low sulfur transportation diesel). No add-on control technologies are listed in the RACT/BACT/LAER Clearinghouse listings for combustion turbines. Proper combustion control and the firing of fuels with negligible or zero ash content (natural gas for the turbine duct burners and auxiliary boiler and low sulfur transportation diesel for the firewater pump and back-up diesel generator) is the predominant control method listed.

Add-on controls, such as ESPs or baghouses, have never been applied to commercial gas/oil fired turbines or diesels engines. The use of ESPs and baghouse filters is considered technically infeasible, and does not represent an available control technology.

Summary

The use of negligible or zero ash fuels such as natural gas and low sulfur diesel and good combustion control is concluded to represent BACT for PM_{10} control for the proposed gas turbines, duct burners auxiliary boiler and diesel engines. These operational controls will limit PM_{10} emissions (EPA Reference Method 5/202) to approximately 28 lbs/hr per turbine, including duct burners.

Cooling Tower

Cooling towers are designed to efficiently evaporate water. As water evaporates, it absorbs heat, causing the remaining water to become colder. The cold water is then circulated in non-contact heat exchangers to remove heat from the steam condenser. Water not lost to evaporation in the cooling tower is used for non-contact cooling of the steam turbine condenser. This water will likely contain dissolved solids such as calcium, sodium and potassium. As the water is evaporated in the cooling tower, these total dissolved solids (TDS) tend to concentrate in the water that remains circulating within the cooling tower.

To improve evaporation rate, cooling towers are designed to induce a flow of fresh air across a large wetted surface area (called "fill"). This induced airflow, however, entrains some of the fine water droplets that carry out of the tower, referred to as drift. These fine droplets subsequently evaporate in the ambient air, but when they do they liberate the total dissolved solids that were formerly in solution as emissions of particulate and PM_{10}.

The technologies which are available to control PM_{10} emissions from evaporative cooling towers are limited to devices which seek to minimize drift. Known as Drift Eliminators, this technology represents the top level of control of PM_{10} emissions from evaporative cooling towers. Drift Eliminators typically consist of layers of plastic chevrons located within the tower to knock out and coalesce fine water droplets before they can be emitted to the atmosphere.

The Washington Energy Facility evaluated drift performance guarantees based on state-of-the-art Drift Eliminators. Based on this, a guaranteed level of 0.001 percent of circulating water flow was obtained for this project. This level of control results in a potential annual emission of PM_{10} from the cooling tower of 8.6 tpy. Drift Eliminators are therefore concluded to represent BACT for PM_{10} for the Project.

Control of Hydrocarbons and Trace Organics

Formation

Non-methane hydrocarbons (also referred to as volatile organic compounds or VOCs) and trace organics are emitted from gas-fired turbines as a result of incomplete combustion of fuel. Control of these pollutants is accomplished by providing adequate fuel residence time and high temperature in the combustion zone to ensure complete combustion.

Gas Turbines

An oxidation catalyst designed to control CO would provide a side benefit of controlling a portion of the VOC emissions. The level of control is dependent on the content of the natural gas. To date, vendors have not been willing to provide guarantees on oxidation catalysts for VOC control. The next level of control is combustion controls where VOC emissions are minimized by optimizing fuel mixing, excess air, and combustion temperature to assure complete combustion of the fuel.

The same technical factors that apply to the use of oxidation catalyst technology for control of CO emissions (narrow operating temperature range, loss of catalyst activity over time, and system pressure losses) apply to the use of this technology for collateral control of VOC. Since the Project will not employ a CO catalyst, the collateral reductions in VOC are not available.

Since an oxidation catalyst was shown to not be cost effective for control of CO, it would not be cost effective for control of VOCs at a much lower emission rate (20% of the CO annual emissions) and lower control efficiency. An oxidation catalyst is therefore no longer considered as a BACT option for this Project. The proposed emission rate (1.4 ppmvd without duct firing and less than 10 ppmvd with duct firing), based on operational controls only is in the same range as facilities which also employ oxidation catalyst. Therefore, this level of operational control is concluded to represent BACT for the Washington Energy Facility.

Duct Burners and Auxiliary Boiler

The duct burners and auxiliary boiler will employ good combustion control for emissions of a VOC, with a VOC emission rate of 0.03 and 0.014 lb/MMBtu, respectively. The use of natural gas and good combustion control represent BACT for VOC from the duct burners and auxiliary boiler.

Diesel Firewater Pump and Back-up Generator

Add on control technology is not available for control of VOC emissions from diesel engines which operate less than 500 hours/yr. Good combustion control practices, therefore, represent BACT for VOC from the Project's diesel fire pump and back-up diesel engine.

Control of Other Non-Criteria Pollutants

The combustion of natural gas and diesel fuel may release trace amounts of a number of non-criteria pollutants. One of the PSD regulated pollutants (sulfuric acid mist) requires a BACT analysis as defined by EPA. Sulfuric acid (H_2SO_4) emissions are based on a conservative estimate that assumes 10 percent of the SO_2 is converted to SO_3 and all the SO_3 converts to sulfuric acid. It is further based on the fact that the turbines, duct burners, and auxiliary boiler will fire natural gas only. The diesel fire pump and back-up generator will fire low sulfur diesel fuel (<0.05% sulfur). It is proposed that BACT for SO_2 also represents BACT for sulfuric acid mist.

Summary

The proposed BACT for the Washington Energy Facility is summarized in Tables 5-2 and 5-3, below.

Table 5-2: Proposed BACT Limits - Combustion Turbine

Pollutant	Selected Controls	Proposed BACT
NO_x	Gas as sole fuel, DLN combustors, & SCR	3.5 ppmvd at 15% O_2
SO_2	Gas as sole fuel	2 grains S/100 CF gas
CO	Good combustion practices	14.2 ppmvd @ 15% 0_2
VOC	Good combustion practices	9.9 ppmvd
PM/PM_{10}	Gas as sole fuel & good combustion practices	0.019 lb/MMBtu

Table 5-3: Proposed BACT Limits - Ancillary Equipment

Pollutant	Auxiliary Boiler	Diesel Engines	Cooling Tower
NO_x	Gas as sole fuel & Low NO_x Burners (0.11 lb/MMBtu)	Operating hours $\leq$ 500 hr/yr	N/A
SO_2	Gas as sole fuel	$\leq$ 0.05 wt % sulfur oil	N/A
CO	Good combustion (0.135 lb/MMBtu)	Operating hours $\leq$ 500 hr/yr	N/A
VOC	Good combustion (0.014 lb/MMBtu)	Operating hours $\leq$ 500 hr/yr	N/A
PM/PM_{10}	Gas as sole fuel (0.009 lb/MMBtu)	Operating hours $\leq$ 500 hr/yr	Drift eliminator $\leq$ 0.001%

Ambient Air Quality Monitoring Requirements

The Washington Energy Facility installation is located in Air Quality Control Region (AQCR) 177. The area is attainment or attainment/unclassifiable for total suspended particulates, particulate matter less than 10 microns, sulfur dioxide, nitrogen oxides, carbon monoxide, volatile organic compounds (ozone) and lead.

U.S. EPA regulations require a year of ambient air quality data to be obtained as part of the PSD application. An applicant may conduct monitoring on-site, model to demonstrate a "de minimus" impact, or used existing air quality data to fill some of the requirements of a PSD ambient air quality analysis. If monitoring is required, U.S. EPA has set up specific conditions on the acceptability of existing air quality monitors is to ensure the monitor is representative of air quality in the area.

In this instance, Duke Energy Washington, LLC has conducted ambient air quality modeling that predicts the ambient air quality impact of the source(s) to be less than the monitoring de minimus concentrations for NO_2, PM_{10}, SO_2, and CO. Therefore, Duke Energy Washinton, LLC would not be required to conduct pre-application monitoring. A summary is below:

Pollutant	Averaging Period	Monitoring Predicted Concentration	Monitoring De Minimus Concentration

NO_2	Annual*	0.23 ug/m^3	14 ug/m^3
CO	8-hour high	25.9 ug/m^3	575 ug/m^3
PM_{10}	24-hour high	1.9 ug/m^3	10 ug/m^3
SO_2	24-hour high**	2.9 ug/m^3	13 ug/m^3

*Annual average based on weighted oil-fired (500 hours) and gas-fired (2,000 hours) impacts.

**SO_2 and NO_2 impacts based on 8 AM to 8 PM oil-fired operation.

Modeling

Air quality dispersion modeling was conducted to assess the effect of these sources on ambient air quality standards and PSD increments. The U.S. EPA Industrial Source Complex-Short Term (ISCST3, Version 97363) model was used for the refined modeling analysis. This refined modeling was performed after SCREEN3 modeling indicated significant impacts from the Project. The purposed of the refined modeling was to demonstrate that projects impacts were insignificant and that PSD and NAAQS analyses would be unnecessary.

The ISCST3, Version 97363 model was the appropriate model for this analysis, based on the need to model simple to intermediate terrain, the need to incorporate building wake effects, the need to predict both short-term and long-term (annual) average concentrations, and the need to incorporate impacts from multiple and separated emissions units.

The ISCST3, Version 97363 model was run with the regulatory default options (stack-tip downwash, buoyancy-induced dispersion, final plume rise), default wind speed profile categories, default potential temperature gradient, and no pollutant decay. Building downwash was assessed using either the Huber-Snyder or Schulman-Sire downwash methodology, depending on the stack and nearby building heights.

The ISCST3, Version 97363 model was run utilizing the National Weather Service meteorological data processed using the U.S. EPA PCRAMMET program. OEPA provided five years of the most recent PCRAMMET processed meteorological data on their bulletin board system. Following OEPA modeling guidance concerning representative meteorological data for various counties, the Cincinnati Surface, Dayton Upper Air (1987-1991) PCRAMMET data were used in the refined modeling analysis.

Building wake effects will influence emissions from stacks with heights less than Good Engineering Practice (GEP). The ISCST3, Version 97363 model requires input of building heights and projected building widths for 36 wind directions. The U.S. EPA Building Profile Input Program (BPIP) was used to determine the direction-specific building dimensions.

Modeling Results/Increment Analysis

Modeling at 100%, 75% and 50% loads, for natural gas, and using stack parameters based on average as well as extreme ambient temperatures, was performed to determine the worst case impacts for each pollutant. The results are as follows: The maximum predicted annual and 24-hour average PM_{10} concentration of 0.03 and 1.9 ug/m^3, respectively, were below the corresponding significant impact increments of 1 and 5 ug/m^3. Therefore, no additional dispersion modeling analyses for PM_{10} were necessary for PM.

The maximum predicted 1-hour and 8-hour CO concentration of 34.9 and 25.9 ug/m^3 respectively were below the corresponding significant impact increments of 2000 and 500 ug/m^3. Therefore, no additional dispersion

modeling analysis were necessary for CO.

The maximum predicted annual NO_2 concentration of 0.23 ug/m^3 was below the corresponding significant impact increment of 1.0 ug/m^3. Therefore no additional dispersion analysis was necessary for NO_2.

The maximum predicted annual, 24-hour and 3-hour average SO_2 concentrations of 0.02, 2.9 and 14.5 ug/m^3 were below the corresponding significant impart increments of 1.0, 5.0 and 25.0 ug/m^3. Therefore, no additional dispersion modeling analysis was necessary for SO_2.

Secondary Impact

The closest Class I area to the Washington Energy Facility is the Mammoth Cave National Park (Kentucky) which is approximately 247 km to the southwest. Federal PSD regulation regulations require that the reviewing authority provide written notification of projects which may affect a Class 1 area. "May effect" is typically interpreted by EPA as a major source or major modification within 100 kilometers. Since the Washington Energy Facility is located greater than 100 kilometers from any Class I area, and all modeled impacts are below Significant Impact Levels, the Washington Energy Facility was not subject to the visibility analysis modeling.

Most of the designated vegetation screening levels are equivalent to or exceed NAAQS and/or PSD increments, so that satisfaction of NAAQS and PSD increment assures compliance with sensitive vegetation screening levels. For SO_2 3-hour and annual averaging periods, sensitive screening levels are more stringent than comparable NAAQS standards. The results demonstrate maximum concentrations are well below sensitive levels.

The project is to employ approximately 15 permanent positions during operations and an average of 200 people during construction. It is not expected that there will be regional population, commercial, or industrial growth associated with this project.

Conclusions

Based upon analysis of the permit to install application and it's supporting documentation provided by Duke Energy Washington, LLC, the Ohio EPA staff has determined that the proposed increase will comply with all applicable State and Federal environmental regulations and that the requirements for BACT are satisfied. Therefore, the Ohio EPA staff recommends that a permit to install be issued to Duke Energy Washington, LLC.

State of Ohio Environmental Protection Agency

RE: DRAFT PERMIT TO INSTALL **CERTIFIED MAIL**
WASHINGTON COUNTY

Street Address: Mailing Address: Lazarus Gov. Center
Lazarus Gov. Center **TELE:** (614) 644-3020 **FAX:** (614) 644-2329

Application No: 06-06167

DATE: 10/19/2000

Duke Energy Washington County LLC
William C Campbell III
5400 Westheimer Court
Houston, TX 77056

You are hereby notified that the Ohio Environmental Protection Agency has made a draft action recommending that the Director issue a Permit to Install for the air contaminant source(s) [emissions unit(s)] shown on the enclosed draft permit. This draft action is not an authorization to begin construction or modification of your emissions unit(s). The purpose of this draft is to solicit public comments on the proposed installation. A public notice concerning the draft permit will appear in the Ohio EPA Weekly Review and the newspaper in the county where the facility will be located. Public comments will be accepted by the field office within 30 days of the date of publication in the newspaper. Any comments you have on the draft permit should be directed to the appropriate field office within the comment period. A copy of your comments should also be mailed to Robert Hodanbosi, Division of Air Pollution Control, Ohio EPA, P.O. Box 1049, Columbus, OH, 43266-0149.

A Permit to Install may be issued in proposed of final form based on the draft action, any written public comments received within 30 days of the public notice, or record of a public meeting if one is held. You will be notified in writing of a scheduled public meeting. Upon issuance of a final Permit to Install a fee of **$600** will be due. Please do not submit any payment now.

The Ohio EPA is urging companies to investigate pollution prevention and energy conservation. Not only will this reduce pollution and energy consumption, but it can also save you money. If you would like to learn ways you can save money while protecting the environment, please contact our Office of Pollution Prevention at (614) 644-3469. If you have any questions about this draft permit, please contact the field office where you submitted your application, or Mike Ahern, Field Operations & Permit Section at (614) 644-3631.
Very truly yours,

Thomas G. Rigo
Field Operations and Permit Section
Division of Air Pollution Control

CC: **USEPA** **SEDO**
Alan Lloyd **OEPA/DAPC**

DRAFT PERMIT TO INSTALL 06-06167

Application Number:	06-06167
APS Premise Number:	0684000212
Permit Fee:	**To be entered upon final issuance**
Name of Facility:	Duke Energy Washington County LLC
Person to Contact:	William C Campbell III
Address:	5400 Westheimer Court Houston, TX 77056

Location of proposed air contaminant source(s) [emissions unit(s)]:
State Route 83
Beverly, Ohio

Description of proposed emissions unit(s):
Baseload natural gas fired combined cycle power plant 620 MW.

The above named entity is hereby granted a Permit to Install for the above described emissions unit(s) pursuant to Chapter 3745-31 of the Ohio Administrative Code. Issuance of this permit does not constitute expressed or implied approval or agreement that, if constructed or modified in accordance with the plans included in the application, the above described emissions unit(s) of environmental pollutants will operate in compliance with applicable State and Federal laws and regulations, and does not constitute expressed or implied assurance that if constructed or modified in accordance with those plans and specifications, the above described emissions unit(s) of pollutants will be granted the necessary permits to operate (air) or NPDES permits as applicable.

This permit is granted subject to the conditions attached hereto.

Ohio Environmental Protection Agency

Director

A. State and Federally Enforceable Permit To Install General Terms and Conditions

1. Monitoring and Related Recordkeeping and Reporting Requirements

a. Except as may otherwise be provided in the terms and conditions for a specific emissions unit, the permittee shall maintain records that include the following, where applicable, for any required monitoring under this permit:

i. The date, place (as defined in the permit), and time of sampling or measurements.

ii. The date(s) analyses were performed.

iii. The company or entity that performed the analyses.

iv. The analytical techniques or methods used.

v. The results of such analyses.

vi. The operating conditions existing at the time of sampling or measurement.

b. Each record of any monitoring data, testing data, and support information required pursuant to this permit shall be retained for a period of five years from the date the record was created. Support information shall include, but not be limited to, all calibration and maintenance records and all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required by this permit. Such records may be maintained in computerized form.

c. Except as may otherwise be provided in the terms and conditions for a specific emissions unit, the permittee shall submit required reports in the following manner:

i. Reports of any required monitoring and/or recordkeeping of federally enforceable information shall be submitted to the appropriate Ohio EPA District Office or local air agency.

ii. Quarterly written reports of (i) any deviations from federally enforceable emission limitations, operational restrictions, and control device operating parameter limitations, excluding deviations resulting from malfunctions reported in accordance with OAC rule 3745-15-06, that have been detected by the testing, monitoring and recordkeeping requirements specified in this permit, (ii) the probable cause of such deviations, and (iii) any corrective actions or preventive measures taken, shall be made to the appropriate Ohio EPA District Office or local air agency. The written reports shall be submitted quarterly, i.e., by January 31, April 30, July 31, and October 31 of each year and shall cover the previous calendar quarters. See B.11 below if no deviations occurred during the quarter.

iii. Written reports, which identify any deviations from the federally enforceable monitoring, recordkeeping, and reporting requirements contained in this permit shall be submitted to the appropriate Ohio EPA District Office or local air agency every six months, i.e., by January 31 and July 31 of each year for the previous six calendar months. If no deviations occurred during a six-month period, the permittee shall submit a semi-annual report, which states that no deviations occurred during that period.

iv. Each written report shall be signed by a responsible official certifying that, based on information and belief formed after reasonable inquiry, the statements and information in the report are true, accurate, and complete.

2. Scheduled Maintenance/Malfunction Reporting

Any scheduled maintenance of air pollution control equipment shall be performed in accordance with paragraph (A) of OAC rule 3745-15-06. The malfunction, i.e., upset, of any emissions units or any associated air pollution control system(s) shall be reported to the appropriate Ohio EPA District Office or local air agency in accordance with paragraph (B) of OAC rule 3745-15-06. (The definition of an upset condition shall be the same as that used in OAC rule 3745-15-06(B)(1) for a malfunction.) The verbal and written reports shall be submitted pursuant to OAC rule 3745-15-06**.**
Except as provided in that rule, any scheduled maintenance or malfunction necessitating the shutdown or bypassing of any air pollution control system(s) shall be accompanied by the shutdown of the emission unit(s) that is (are) served by such control system(s).

3. Risk Management Plans

If the permittee is required to develop and register a risk management plan pursuant to section 112(r) of the Clean Air Act, as amended, 42 U.S.C. 7401 et seq. ("Act"), the permittee shall comply with the requirement to register such a plan.

4. Title IV Provisions

If the permittee is subject to the requirements of 40 CFR Part 72 concerning acid rain, the permittee shall ensure that any affected emissions unit complies with those requirements. Emissions exceeding any allowances that are lawfully held under Title IV of the Act, or any regulations adopted thereunder, are prohibited.

5. Severability Clause

A determination that any term or condition of this permit is invalid shall not invalidate the force or effect of any other term or condition thereof, except to the extent that any other term or condition depends in whole or in part for its operation or implementation upon the term or condition declared invalid.

6. General Requirements

a. The permittee must comply with all terms and conditions of this permit. Any noncompliance with the federally enforceable terms and conditions of this permit constitutes a violation of the Act, and is grounds for enforcement action or for permit revocation, revocation and reissuance, or modification, or for denial of a permit renewal application.

b. It shall not be a defense for the permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the federally enforceable terms and conditions of this permit.

c. This permit may be modified, reopened, revoked, or revoked and reissued, for cause. The filing of a request by the permittee for a permit modification, revocation and reissuance, or revocation, or of a notification of planned changes or anticipated noncompliance does not stay any term and condition of this permit.

d. This permit does not convey any property rights of any sort, or any exclusive privilege.

e. The permittee shall furnish to the Director of the Ohio EPA, or an authorized representative of the Director, upon receipt of a written request and within a reasonable time, any information that may be requested to determine whether cause exists for modifying, reopening or revoking this permit or to determine compliance with this permit. Upon request, the permittee shall also furnish to the Director or an authorized representative of the Director, copies of records required to be kept by this permit. For information claimed to be confidential in the submittal to the Director, if the Administrator of the U.S. EPA requests such information, the permittee may furnish such records directly to the Administrator along with a claim of confidentiality.

7. Fees

The permittee shall pay fees to the Director of the Ohio EPA in accordance with ORC section 3745.11 and OAC Chapter 3745-78. The permittee shall pay all applicable Permit To Install fees within 30 days after the issuance of this Permit To Install.

8. Federal and State Enforceability

Only those terms and conditions designated in this permit as federally enforceable, that are required under the Act, or any of its applicable requirements, including relevant provisions designed to limit the potential to emit of a source, are enforceable by the Administrator of the U.S. EPA, the State, and citizens under the Act. All other terms and conditions of this permit shall not be federally enforceable and shall be enforceable under State law only.

9. Compliance Requirements

a. Any document (including reports) required to be submitted and required by a federally

applicable requirement in this permit shall include a certification by a responsible official that, based on information and belief formed after reasonable inquiry, the statements in the document are true, accurate, and complete.

b. Upon presentation of credentials and other documents as may be required by law, the permittee shall allow the Director of the Ohio EPA or an authorized representative of the Director to:

i. At reasonable times, enter upon the permittee's premises where a source is located or the emissions-related activity is conducted, or where records must be kept under the conditions of this permit.

ii. Have access to and copy, at reasonable times, any records that must be kept under the conditions of this permit, subject to the protection from disclosure to the public of confidential information consistent with ORC section 3704.08.

iii. Inspect at reasonable times any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under this permit.

iv. As authorized by the Act, sample or monitor at reasonable times substances or parameters for the purpose of assuring compliance with the permit and applicable requirements.

c. The permittee shall submit progress reports to the appropriate Ohio EPA District Office or local air agency concerning any schedule of compliance for meeting an applicable requirement. Progress reports shall be submitted semiannually, or more frequently if specified in the applicable requirement or by the Director of the Ohio EPA. Progress reports shall contain the following:

i. Dates for achieving the activities, milestones, or compliance required in any schedule of compliance, and dates when such activities, milestones, or compliance were achieved.

ii. An explanation of why any dates in any schedule of compliance were not or will not be met, and any preventive or corrective measures adopted.

10. Permit To Operate Application

a. If the permittee is required to apply for a Title V permit pursuant to OAC Chapter 3745-77, the permittee shall submit a complete Title V permit application or a complete Title V permit modification application within twelve (12) months after commencing operation of the emissions units covered by this permit. However, if the proposed new or modified source(s) would be prohibited by the terms and conditions of an existing Title V permit, a Title V permit modification must be obtained before the operation of such new or modified source(s) pursuant to OAC rule 3745-77-04(D) and OAC rule

3745-77-08(C)(3)(d).

b. If the permittee is required to apply for permit(s) pursuant to OAC Chapter 3745-35 , the source(s) identified in this Permit To Install is (are) permitted to operate for a period of up to one year from the date the source(s) commenced operation. Permission to operate is granted only if the facility complies with all requirements contained in this permit and all applicable air pollution laws, regulations, and policies. Pursuant to OAC Chapter 3745-35, the permittee shall submit a complete operating permit application within thirty (30) days after commencing operation of the source(s) covered by this permit.

B. State Only Enforceable Permit To Install General Terms and Conditions

1. Compliance Requirements

The emissions unit(s) identified in this Permit to Install shall remain in full compliance with all applicable State laws and regulations and the terms and conditions of this permit.

2. Reporting Requirements Related to Monitoring and Recordkeeping Requirements

The permittee shall submit required reports in the following manner:

a. Reports of any required monitoring and/or recordkeeping of state-only enforceable information shall be submitted to the appropriate Ohio EPA District Office or local air agency.

b. Except as otherwise may be provided in the terms and conditions for a specific emissions unit, quarterly written reports of (a) any deviations (excursions) from state-only required emission limitations, operational restrictions, and control device operating parameter limitations that have been detected by the testing, monitoring, and recordkeeping requirements specified in this permit, (b) the probable cause of such deviations, and (c) any corrective actions or preventive measures which have been or will be taken, shall be submitted to the appropriate Ohio EPA District Office or local air agency. If no deviations occurred during a calendar quarter, the permittee shall submit a quarterly report, which states that no deviations occurred during that quarter. The reports shall be submitted quarterly, i.e., by January 31, April 30, July 31, and October 31 of each year and shall cover the previous calendar quarters. (These quarterly reports shall exclude deviations resulting from malfunctions reported in accordance with OAC rule 3745-15-06.)

3. Permit Transfers

Any transferee of this permit shall assume the responsibilities of the prior permit holder. The appropriate Ohio EPA District Office or local air agency must be notified in writing of any transfer of this permit.

4. Air Pollution Nuisance

The air contaminants emitted by the emissions units covered by this permit shall not cause a public nuisance, in violation of OAC rule 3745-15-07.

5. Termination of Permit To Install

This permit to install shall terminate within eighteen months of the effective date of the permit to install if the owner or operator has not undertaken a continuing program of installation or modification or has not entered into a binding contractual obligation to undertake and complete within a reasonable time a continuing program of installation or modification. This deadline may be extended by up to 12 months if application is made to the Director within a reasonable time before the termination date and the party shows good cause for any such extension.

6. Construction of New Sources(s)

The proposed emissions unit(s) shall be constructed in strict accordance with the plans and application submitted for this permit to the Director of the Ohio Environmental Protection Agency. There may be no deviation from the approved plans without the express, written approval of the Agency. Any deviations from the approved plans or the above conditions may lead to such sanctions and penalties as provided under Ohio law. Approval of these plans does not constitute an assurance that the proposed facilities will operate in compliance with all Ohio laws and regulations. Additional facilities shall be installed upon orders of the Ohio Environmental Protection Agency if the proposed sources are inadequate or cannot meet applicable standards.

If the construction of the proposed emissions unit(s) has already begun or has been completed prior to the date the Director of the Environmental Protection Agency approves the permit application and plans, the approval does not constitute expressed or implied assurance that the proposed facility has been constructed in accordance with the approved plans. The action of beginning and/or completing construction prior to obtaining the Director's approval constitutes a violation of OAC rule 3745-31-02. Furthermore, issuance of the Permit to Install does not constitute an assurance that the proposed source will operate in compliance with all Ohio laws and regulations. Approval of the plans in any case is not to be construed as an approval of the facility as constructed and/or completed. Moreover, issuance of the Permit to Install is not to be construed as a waiver of any rights that the Ohio Environmental Protection Agency (or other persons) may have against the applicant for starting construction prior to the effective date of the permit. Additional facilities shall be installed upon orders of the Ohio Environmental Protection Agency if the proposed facilities prove to be inadequate or cannot meet applicable standards.

7. Public Disclosure

The facility is hereby notified that this permit, and all agency records concerning the operation of this permitted source, are subject to public disclosure in accordance with OAC rule 3745-49-03.

8. Applicability

This Permit to Install is applicable only to the emissions unit(s) identified in the Permit To Install. Separate application must be made to the Director for the installation or modification of any other emissions unit(s).

9. Best Available Technology

As specified in OAC Rule 3745-31-05, all new sources must employ Best Available Technology (BAT). Compliance with the terms and conditions of this permit will fulfill this requirement.

10. Construction Compliance Certification

The applicant shall provide Ohio EPA with a written certification (see enclosed form) that the facility has been constructed in accordance with the Permit To Install application and the terms and conditions of the Permit to Install. The certification shall be provided to Ohio EPA upon completion of construction but prior to startup of the source.

11. Additional Reporting Requirements When There Are No Deviations of Federally Enforceable Emission Limitations, Operational Restrictions, or Control Device Operating Parameter Limitations (See Section A of This Permit)

If no deviations occurred during a calendar quarter, the permittee shall submit a quarterly report, which states that no deviations occurred during that quarter. The reports shall be submitted quarterly, i.e., by January 31, April 30, July 31, and October 31 of each year and shall cover the previous calendar quarters.

C. Permit To Install Summary of Allowable Emissions

The following information summarizes the total allowable emissions, by pollutant, based on the individual allowable emissions of each air contaminant source identified in this permit.

SUMMARY (for informational purposes only)
TOTAL PERMIT TO INSTALL ALLOWABLE EMISSIONS

Pollutant	Tons Per Year
NOx	316.3
SO2	113.1
CO	909
VOC	126.4
PM	207.3
ammonia (NH3)	269
formaldehyde	7.2
sulfuric acid	17.2

Part II - FACILITY SPECIFIC TERMS AND CONDITIONS

A. State and Federally Enforceable Permit To Install Facility Specific Terms and Conditions

NONE

B. State Only Enforceable Permit To Install Facility Specific Terms and Conditions

NONE

Part III - SPECIAL TERMS AND CONDITIONS FOR SPECIFIC EMISSIONS UNIT(S)

A. State and Federally Enforceable Section

I. Applicable Emissions Limitations and/or Control Requirements

1. The specific operations(s), property, and/or equipment which constitute this emissions unit are listed in the following table along with the applicable rules and/or requirements and with the applicable emissions limitations and/or control measures. Emissions from this unit shall not exceed the listed limitations, and the listed control measures shall be specified in narrative form following the table.

Operations, Property, and/or Equipment	Applicable Rules/Requirements
B001 - 46.6 MMBtu/hr natural gas fired boiler	OAC rule 3745-31-05(A)(3)
	40 CFR 60 Subpart Dc OAC rule 3745-18-06(A)
	OAC rule 3745-17-10(B)(1)
	OAC rule 3745-17-07(A)
	40 CFR 52.21 OAC rule 3745-31- (13) thru (20)

Applicable Emissions Limitations/Control Measures	
The requirements of this rule also include compliance with the requirements of 40 CFR 60 Subpart Dc, OAC rule 3745-18-06(A), 3745-17-10(B)(1), OAC rule 3745-17-07(A), 40 CFR 52.21, and OAC 3745-31-(13) thru (20).	year particulate matter (PM) emissions shall not exceed 0.932 lb/hr, and 0.23 ton per year The emission limitations specified by these rules are less stringent than those established above; 0.020 lb PM/MMBtu actual heat input, 20% opacity as a six minute average, except as provided by rule The tons per rolling 12-month period shall not exceed : NOx - 1.3 SO2 - 0.07 PM - 0.23 CO - 1.7 VOC - 0.18
nitrogen oxide (NOx) emissions shall not exceed 0.11 lb/MMBtu actual heat input 5.3 lb/hr, and 1.3 ton per year	
sulfur dioxide (SO2) emissions shall not exceed 0.0057 lb/MMBtu actual heat input 0.28 lb/hr, and 0.07 ton per year	
carbon monoxide (CO) emissions shall not exceed 0.14 lb/MMBtu actual heat input 6.62 lb/hr, and 1.7 ton per year	
volatile organic compounds (VOC) emissions shall not exceed 0.014 lb/MMBtu actual heat input 0.7 lb/hr, and 0.18 ton per	

Emissions Unit ID: B001

Duke Energy Washington County LLC **Facility ID: 0684000212**
PTI Application: 06-06167
Issued: To be entered upon final issuance

2. Additional Terms and Conditions

2.a NONE

II. Operational Restrictions

1. The permittee shall burn only natural gas in this emission unit. The maximum sulfur content of the natural gas shall not exceed 2 grains per 100 standard cubic feet.

2. The maximum annual hours of operation of emissions unit B001 shall not exceed 500 hours, based upon a rolling, 12-month summation.

To ensure enforceability during the first 12 calendar months following the startup of this emissions unit the permittee shall not exceed the monthly hours of operation restrictions specified in the following table:

Month	Cumulative hours of Operation
1	300
1-2	500
1-3	500
1-4	500
1-5	500
1-6	500
1-7	500
1-8	500
1-9	500
1-10	500
1-11	500
1-12	500

After the first 12 calendar months following the startup of emissions unit B001, compliance with the annual hours of operation restriction shall be based on a rolling, 12-month summation.

III. Monitoring and/or Recordkeeping Requirements

1. For each day during which the permittee burns a fuel other than natural gas, the permittee shall maintain a record of the type and quantity of fuel burned in this emissions unit

2. The permittee shall monitor the sulfur content and gross calorific value of the fuel being fired in the emission unit. Fuel sampling and analysis shall be conducted according to the procedures and at the frequency specified by 40 CFR Part 75, Appendix D.

3. The permittee shall maintain monthly records of the following information for each emissions

unit:

a. Hours of operation of the boiler;

b. Beginning after the first 12 calendar months of operation following issuance of this permit, the rolling, 12-month summation of the hours of operation.

Also, during the first 12 calendar months of operation following issuance of this permit, the permittee shall record the cumulative hours of operation for each calendar month.

IV. Reporting Requirements

1. The permittee shall submit deviation (excursion) reports that identify each day when a fuel other than natural gas was burned in this emissions unit. Each report shall be submitted within 30 days after the deviation occurs.

2. The permittee shall submit deviation (excursion) reports that identify any record which shows that the sulfur content of the natural gas exceeded 2 grains per standard cubic foot. These reports are due by the date described in Part I - General Terms and Conditions of this permit under section (A)(2).

3. The permittee shall submit deviation (excursion) reports which identify all exceedances of the rolling, 12-month operating hours limitation and, for the first 12 calendar months of operation, all exceedances of the maximum allowable cumulative operating hours levels. These reports are due by the date described in Part 1 - General Terms and Conditions of this permit under section (A)(2).

4. This emissions unit is subject to the applicable provisions of Subpart Dc of the New Source Performance Standards (NSPS) as promulgated by the United States Environmental Protection Agency, 40 CFR Part 60. The application and enforcement of these standards are delegated to the Ohio EPA. The requirements of 40 CFR Part 60 are also federally enforceable.

Pursuant to 40 CFR Part 60.7, the permittee is hereby advised of the requirement to report the following at the appropriate times:

a. construction date (no later than 30 days after such date);

b. anticipated start-up date (not more than 60 days or less than 30 days prior to such date);

c. actual start-up date (within 15 days after such date); and,

d. date of performance testing (if required, at least 30 days prior to testing).

Reports are to be sent to:

Ohio Environmental Protection Agency
DAPC - Permit Management Unit
P. O. Box 163669
Columbus, Ohio 43216-3669

and

Ohio Environmental Protection Agency
Southeast District Office
Division of Air Pollution Control
2195 Front Street
Logan, Ohio 43138

5. PSD REQUIREMENTS

The source described in this Permit to Install is subject to the applicable provisions of the Prevention of Significant Deterioration (PSD) regulations as promulgated by the United States Environmental Protection Agency 40 CFR 52.21. The authority to apply and enforce the PSD regulations has been delegated to the Ohio Environmental Protection Agency. The terms and conditions of this permit and the requirements of the PSD regulations are also enforceable by the United States Environmental Protection Agency.

In accordance with 40 CFR 124.15, 124.19 and 124.20, the following shall apply: (1) the effective date of this permit shall be 30 days after the service of notice to any public commentors of the final decision to issue, modify, or revoke and re-issue the permit, unless the service of notice is by mail, in which case the effective date of the permit shall be 33 days after the service of notice; and (2) if an appeal is made to the Environmental Appeals Board of the United States Environmental Protection Agency, the effective date of the permit is suspended until such time as the appeal is resolved or denied.

Appeals will be addressed to:

United States Environmental Protection Agency
Environmental Appeals Board
401 M Street, SW (MC-113do)
Washington, DC 20460

V. Testing Requirements

1. Emission Limitation:

NOx
0.11 lb/MMBtu, 5.3 lb/hr, and 1.3 tons per year

Applicable Compliance Method:

lb/MMBtu
Compliance shall be demonstrated using the manufacturer supplied performance data emission factor (0.011 lb NOx /MMBTU).

lb/hr
Compliance shall be demonstrated by multiplying the manufacturer supplied performance data emission factor (0.011 lb NOx /MMBTU) by the maximum Btu input rate (46.6 MMBTU/hr) X 1.05 maximum load operations.

tons per year
Compliance shall be demonstrated by multiplying the hourly NOx emission rate (5.3 lb/hr) by actual hours/year and dividing by 2000 lb/ton.

2. Emission Limitation:

SO2
0.0057 lb/MMBTU, 0.28 lb/hr, and 0.07 tons per year

Applicable Compliance Method:

lb/MMBTU
Compliance shall be demonstrated using the manufacturer supplied performance data emission factor (0.0057 lb SO2 /MMBTU).

lb/hr
Compliance shall be demonstrated by multiplying the manufacturer supplied performance data emission factor (0.0057 lb SO2 /MMBTU) by the maximum Btu input rate (46.6 MMBTU/hr) X 1.05 maximum load operation.

tons per year
Compliance shall be demonstrated by multiplying the hourly SO2 emission rate (0.28 lb/hr) by actual hours/year and dividing by 2000 lb/ton.

3. Emission Limitation:

CO
0.14 lb/MMBTU, 6.62 lb/hr, and 1.7 tons per year

Applicable Compliance Method:

lb/MMBTU
Compliance shall be demonstrated using the manufacturer supplied performance data emission factor (0.14 lb CO /MMBTU)

lb/hr
Compliance shall be demonstrated by multiplying the manufacturer supplied performance data emission factor (0.l4 lb CO /MMBTU) by the maximum Btu input rate (46.6 MMBTU/hr) X 1.05 maximum load operation..

tons per year
Compliance shall be demonstrated by multiplying the hourly emission rate (6.62 lb/hr) by actual hours/year and dividing by 2000 lb/ton.

4. Emission Limitation:

VOC
0.014 lb/MMBTU, 0.7 lb/hr, and 0.18 tons per year

Applicable Compliance Method:

lb/MMBTU
Compliance shall be demonstrated using the manufacturer supplied performance data emission factor (0.014 lb VOC /MMBTU).

lb/hr
Compliance shall be demonstrated by multiplying the manufacturer supplied performance data emission factor (0.0l4 lb VOC /MMBTU) by the maximum Btu input rate (46.6 MMBTU/hr) X 1.05 maximum load operation.

tons per year
Compliance shall be demonstrated by multiplying the hourly emission rate (0.7 lb/hr) by actual hours/year and dividing by 2000 lb/ton.

5. Emission Limitation:

PM
0.02 lb/MMBTU, 0.932 lb/hr, and 0.23 ton per year

Applicable Compliance Method:

lb/MMBTU
Compliance shall be demonstrated using the manufacturer supplied performance data emission factor (0.010 lb PM /MMBTU).

lb/hr
Compliance shall be demonstrated by multiplying the manufacturer supplied performance data emission factor (0.010 lb PM /MMBTU) by the maximum Btu input rate (46.6 MMBTU/hr) X 1.05 maximum load operation. .

tons per year
Compliance shall be demonstrated by multiplying the hourly emission rate (0.466 lb/hr) by actual hours/year and dividing by 2000 lb/ton.

6. Emission Limitation:
Tons per rolling 12 -month period shall not exceed :
NOx - 1.3
SO2 - 0.07
PM - 0.23
CO - 1.7
VOC - 0.18

Applicable Compliance Method:

Compliance with the annual emission limitations shall be determined by the record keeping required A.III.3. and multiply by the above lb/hr emission rate.

7. Emission Limitation:

Visible particulate emissions shall not exceed 20% opacity as a six-minute average, except as provided by rule.

Applicable Compliance Method:

Compliance shall be demonstrated by the method specified in OAC rule 3745-17-03(B)(1).

VI. Miscellaneous Requirements

NONE

B. State Only Enforceable Section

I. Applicable Emissions Limitations and/or Control Requirements

1. The specific operations(s), property, and/or equipment which constitute this emissions unit are listed in the following table along with the applicable rules and/or requirements and with the applicable emissions limitations and/or control measures. Emissions from this unit shall not exceed the listed limitations, and the listed control measures shall be specified in narrative form following the table.

Operations, Property, and/or Equipment	Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
B001 - 46.6 MMBtu/hr natural gas fired boiler		NONE

2. Additional Terms and Conditions

2.a NONE

II. Operational Restrictions

NONE

III. Monitoring and/or Recordkeeping Requirements

NONE

IV. Reporting Requirements

NONE

V. Testing Requirements

NONE

VI. Miscellaneous Requirements

NONE

Part III - SPECIAL TERMS AND CONDITIONS FOR SPECIFIC EMISSIONS UNIT(S)

A. State and Federally Enforceable Section

I. Applicable Emissions Limitations and/or Control Requirements

1. The specific operations(s), property, and/or equipment which constitute this emissions unit are listed in the following table along with the applicable rules and/or requirements and with the applicable emissions limitations and/or control measures. Emissions from this unit shall not exceed the listed limitations, and the listed control measures shall be specified in narrative form following the table.

Operations, Property, and/or Equipment	Applicable Rules/Requirements	
P001 - 170 MW GE 7FA natural gas-fired dry low NOx (DLN) combustion turbine with duct firing operating in combined cycle mode controlled by Selective Catalytic Reduction (SCR)	OAC Rule 3745-31-05 (A)(3)	
	OAC Rule 3745-31-05 (A)(3)	OAC Rule 3745-31-05 (A)(3)

		40 CFR Part 75 OAC rule 3745-103
OAC Rule 3745-31-05 (A)(3)		
OAC Rule 3745-31-05 (A)(3)	40 CFR part 60, Subpart GG 40 CFR part 60, Subpart Da OAC rule 3745-18-06(F) OAC Rule 3745-17-11 (B)(4) OAC Rule 3745-17-07(A) 40 CFR 52.21 OAC rule 3745-31- (13) thru (20)	

Applicable Emissions Limitations/Control Measures		
The requirements of this rule also include compliance with the requirements of 40 CFR 60 Subpart GG, OAC rule 3745-18-06(F), 3745-17-11(B)(4), OAC rule 3745-17-07(A), 40 CFR 52.21, and OAC 3745-31-(13) thru (20).	shall not exceed 26.6 lbs/hr formaldehyde emissions shall not exceed 0.8 lbs/hr sulfuric acid emissions shall not exceed 1.7 lbs/hr **EMISSION LIMITS WITH DUCT BURNER FIRING (limited to 4,500 hours per year)** nitrogen oxides (NO_x) emissions shall not exceed 3.5 ppmvd at 15% Oxygen and 32.3 lbs /hr PM emissions shall not exceed 28.0 lbs/hr sulfur dioxide (SO_2) shall not exceed 14.5 lbs/hr carbon monoxide (CO) emissions shall not exceed 14 ppmvd at 15% Oxygen and 78.0 lbs/hr volatile organic compounds (VOC) emissions shall not exceed 19.6 lbs/hr ammonia (NH3) emissions shall not exceed 34.6 lbs/hr formaldehyde emissions shall not exceed 0.82 lbs/hr	sulfuric acid emissions shall not exceed 2.2 lbs/hr **STARTUP AND SHUTDOWN EMISSIONS** (also see A.II.3.) nitrogen oxides (NO_x) emissions shall not exceed 32.2 tons per year carbon monoxide (CO) emissions shall not exceed 186.6 tons per year volatile organic compounds (VOC) emissions shall not exceed 12.6 tons per year **TOTAL TONS PER YEAR** (including 4,260 hours per year without duct burners, 4,500 hours per year with duct burners, startups, and shutdowns) nitrogen oxides (NO_x) emissions shall not exceed 157.5 tons per year PM emissions shall not exceed 103.5 tons per year sulfur dioxide (SO_2) shall not exceed 56.5 tons per year carbon monoxide (CO) emissions shall not exceed 453.7 tons per year volatile organic compounds (VOC) emissions shall not exceed 63.1 tons per year

	See A.I.2.c.
ammonia (NH3) emissions shall not exceed 134.5 tons per year	See A.I.2.c.
formaldehyde emissions shall not exceed 3.6 tons per year	
sulfuric acid emissions shall not exceed 8.6 tons per year	
Visible particulate emissions from any stack shall not exceed 10 percent opacity as a six-minute average	
operational restriction, see II. 1.	
see A.2.b.	
see A.2.a.	
see A.2.a.	
see A.2.a.	
see A.2.a.	
The tons per rolling 12-month period shall not exceed : NOx - 157.5 SO2 - 56.5 PM - 103.5 CO - 453.7 VOC - 63.1 H2SO4 - 8.6	

2. Additional Terms and Conditions

2.a The emissions limit based on this applicable rule is equivalent to or less stringent than the limit established pursuant to OAC rule 3745-31-05.

2.b The emissions limits based on this applicable rule are equivalent to or less stringent than the limits established pursuant to OAC rule 3745-31-05. Except as provided for in the terms and conditions in this permit, the permittee is not exempt from meeting any additional requirements of 40 CFR Part 60, Subpart GG.

2.c If the permittee is subject to the requirements of 40 CFR Part 75 concerning acid rain, the permittee shall ensure that any effected emissions unit complies with those requirements. Emissions exceeding any allowances that are lawfully held under Title IV of the Act, or any regulations adopted thereunder, are prohibited.

II. Operational Restrictions

1. The permittee shall burn only natural gas in this emissions unit. The maximum sulfur content of the natural gas shall not exceed 2 grains per 100 standard cubic feet.

2. The permit to install for this emissions unit (P001) was evaluated based actual materials (typical coatings and clean up materials) and the design parameters of the emissions unit's exhaust system, as specified by the permittee in the air permit to install application. The Ohio EPA's "Review of New Sources of Air Toxic Emissions" policy (Air Toxic Policy") was applied for each pollutant emitted by this emissions unit using data from the permit to install application and the SCREEN 3.0 model (or other Ohio EPA approved model). The predicted 1-hour maximum ground-level concentration to the Maximum Acceptable Ground-Level Concentration (MAGLC). The following summarizes the results of the modeling:

Pollutant: Formaldehyde
TLV (ug/m^3): 273 (Converted from the STEL)
Maximum Hourly Emission Rate (lbs/hr): 1.64*
Predicted 1-Hour Maximum Ground-Level Concentration (ug/m3): 0.23
MAGLC (ug/m3): 6.49

Pollutant: Sulfuric Acid
TLV (ug/m3): 1000
Maximum Hourly Emission Rate (lbs/hr): 4.4*
Predicted 1-Hour Maximum Ground-Level Concentration (ug/m3): 2.5
MAGLC (ug/m3): 23.8

Pollutant: Ammonia
TLV (ug/m3): 17000
Maximum Hourly Emission Rate (lbs/hr): 69.2*
Predicted 1-Hour Maximum Ground-Level Concentration (ug/m3): 39.2
MAGLC (ug/m3): 404.8

* This was modeled for emissions units P001 & P002 combined.

Physical changes to or changes in the method of operation of the emissions unit after its installation or modification could affect the parameters used to determine whether or not the "Air Toxic Policy" is satisfied. Consequently, prior to making a change that could impact such parameters, the permittee shall conduct an evaluation to determine that the "Air Toxic Policy" will still be still satisfied. If, upon evaluation, the permittee determines that the "Air Toxic Policy" will not be satisfied, the permittee will not make the change. Changes that can affect the parameters used in applying the "Air Toxic Policy" include the following:

a. changes in the composition of the materials used, or the use of new materials, that would result in the emission of a compound with a lower Threshold Limit Value (TLV), as indicated in the most recent version of the handbook entitled "American Conference of Governmental Industrial Hygienists (ACGIH)," than the lowest TLV value specified in the above table;

b. changes in the composition of the materials, or use of new materials, that would result in an increase in emissions of any pollutant with a listed TLV that was proposed in the application and modeled; and

c. physical changes to the emissions unit or its exhaust parameters (e.g., increased/ decreased exhaust flow, changes in stack height, changes in stack diameter, etc.).

If the permittee determines that the "Air Toxic Policy" will be satisfied for the above changes, the Ohio EPA will not consider the change(s) to be a "modification" under OAC rule 3745-31-01(VV)(1)(a)(ii), and a modification of the existing permit to install will not be required. If the change(s) is (are) defined as a modification under other provisions of the modification definition (other than (VV)(1)(a)(ii)), then the permittee shall obtain a final permit to install prior to the change.

The permittee shall collect, record, and retain the following information when it conducts evaluations to determine that the changed emissions unit will still satisfy the "Air Toxic Policy:"

a. a description of the parameters changed (composition of materials, new pollutants emitted, change in stack/exhaust parameters, etc.);

b. documentation of its evaluation and determination that the changed emissions unit still satisfies the "Air Toxic Policy"; and

c. where computer modeling is performed, a copy of the resulting computer model runs that show the results of the application of the "Air Toxic Policy" for the change.

3. Startup and Shut down shall be defined as when the unit is running at less than 50% of electric load, but under no circumstances shall startups exceed 250 minutes in duration and shutdowns shall not exceed 2 hours in duration. Startup and shutdowns shall be limited to 260 cycles(one startup and one shutdown) per year. Each start up and shutdowns shall be limited to the following:

Pollutant	lbs/start up	lbs/shut down	total lbs/startup and one shutdown
NOx	212.7	35	247.7
CO	1,174	261.5	1435.5
VOC	84.7	12	96.7

4. The maximum annual hours of operation of the duct burners for emissions unit P001 shall not exceed 4,500 hours, based upon a rolling, 12-month summation.

To ensure enforceability during the first 12 calendar months following the startup of this emissions unit, the permittee shall not exceed the monthly hours of operation restrictions specified in the following table:

Month	Cumulative hours of Operation
1	720
1-2	1440
1-3	2160
1-4	2880
1-5	3600
1-6	4320
1-7	4500
1-8	4500
1-9	4500
1-10	4500
1-11	4500
1-12	4500

After the first 12 calendar months following the startup of emissions unit P001, compliance with the annual hours of operation restriction shall be based on a rolling, 12-month summation.

5. Continuous **NOx** Monitoring - Certified Systems

Statement of Certification

Prior to the installation of the continuous ***NO_x*** monitoring system, the permittee shall submit information detailing the proposed location of the sampling site in accordance with the siting requirements in 40 CFR Part 60, Appendix B, Performance Specification 6 for approval by the Ohio EPA, Central Office.

Within 60 days after achieving the maximum production rate at which the emissions unit will be operated, but not later than 180 days after initial startup of such emissions unit, the permittee shall conduct certification tests of such equipment pursuant to the appropriate sections of ORC section 3704.03(I), 40 CFR Part 60, Appendix B, Performance Specification 6, and 40 CFR Part 75. Personnel from the appropriate Ohio EPA District Office or local air agency shall be notified 30 days prior to initiation of the applicable tests and shall be permitted to examine equipment and witness the certification tests. In accordance with OAC rule 3745-15-04, all copies of the test results shall be submitted to the appropriate Ohio EPA District Office or local air agency within 30 days after the test is completed. Copies of the test results shall be sent to the appropriate Ohio EPA District Office or local air agency and the Ohio EPA, Central Office. Certification of the continuous ***NO_x*** monitoring system shall be granted upon determination by the Ohio EPA, Central Office that the system meets all requirements of the appropriate sections of ORC section 3704.03(I), 40 CFR Part 60, Appendix B, Performance Specification 6, and 40 CFR Part 75.

6. Within 180 days of the effective date of this permit, the permittee shall develop a written quality assurance/quality control plan for the continuous NO_x monitoring system designed to ensure continuous valid and representative readings of NO_x emissions in units of the applicable standard. The plan shall follow the requirements of the appropriate sections of 40 CFR Part 60, Appendix F and 40 CFR Part 75, Appendix B. The quality assurance/quality control plan and a logbook dedicated to the continuous NO_x monitoring system must be kept on site and available for inspection during regular office hours.

7. Continuous **CO** Monitoring - Certified Systems
Statement of Certification

Prior to the installation of the continuous ***CO*** monitoring system, the permittee shall submit information detailing the proposed location of the sampling site in accordance with the siting requirements in 40 CFR Part 60, Appendix B, Performance Specification 4 and 6 for approval by the Ohio EPA, Central Office.

Within 60 days after achieving the maximum production rate at which the emissions unit will be operated, but not later than 180 days after initial startup of such emissions unit, the permittee shall

conduct certification tests of the continuous **CO** monitoring system pursuant to ORC section 3704.03(I), 40 CFR Part 60, Appendix B, Performance Specification 4 and 6. Personnel from the appropriate Ohio EPA District Office or local air agency shall be notified 30 days prior to initiation of the applicable tests and shall be permitted to examine equipment and witness the certification tests. In accordance with OAC rule 3745-15-04, all copies of the test results shall be submitted to the appropriate Ohio EPA District Office or local air agency within 30 days after the test is completed. Copies of the test results shall be sent to the appropriate Ohio EPA District Office or local air agency and the Ohio EPA, Central Office. Certification of the continuous **CO** monitoring system shall be granted upon determination by the Ohio EPA Central Office that the system meets all requirements of ORC section 3704.03(I) and 40 CFR Part 60, Appendix B, Performance Specification 4 and 6.

8. Within 180 days of the effective date of this permit, the permittee shall develop a written quality assurance/quality control plan for the continuous **CO** monitoring system designed to ensure continuous valid and representative readings of **CO**. The plan shall follow the requirements of 40 CFR Part 60, Appendix F. The quality assurance/quality control plan and a logbook dedicated to the continuous **CO** monitoring system must be kept on site and available for inspection during regular office hours.

9. Continuous **O_2** or **CO_2** Monitoring - Certified Systems
Statement of Certification

Prior to the installation of the continuous **O_2** or **CO_2** monitoring system, the permittee shall submit information detailing the proposed location of the sampling site in accordance with the siting requirements in 40 CFR Part 60, Appendix B, Performance Specification 3 for approval by the Ohio EPA, Central Office.

Within 60 days after achieving the maximum production rate at which the emissions unit will be operated, but not later than 180 days after initial startup of such emissions unit, the permittee shall conduct certification tests of such equipment pursuant to the appropriate sections of ORC section 3704.03(I), 40 CFR Part 60, Appendix B, Performance Specification 3, and 40 CFR Part 75. Personnel from the appropriate Ohio EPA District Office or local air agency shall be notified 30 days prior to initiation of the applicable tests and shall be permitted to examine equipment and witness the certification tests. In accordance with OAC rule 3745-15-04, all copies of the test results shall be submitted to the appropriate Ohio EPA District Office or local air agency within 30 days after the test is completed. Copies of the test results shall be sent to the appropriate Ohio EPA District Office or local air agency and the Ohio EPA, Central Office. Certification of the continuous **O_2** or **CO_2** monitoring system shall be granted upon determination by the Ohio EPA, Central Office that the system meets all requirements of the appropriate sections of ORC section 3704.03(I), 40 CFR Part 60, Appendix B, Performance Specification 3, and 40 CFR Part 75.

10. Within 180 days of the effective date of this permit, the permittee shall develop a written quality assurance/quality control plan for the continuous **O_2** or **CO_2** monitoring system designed to ensure continuous valid and representative readings of **O_2 or CO_2** emissions in units of the

applicable standard. The plan shall follow the requirements of the appropriate sections of 40 CFR Part 60, Appendix F and 40 CFR Part 75, Appendix B. The quality assurance/quality control plan and a logbook dedicated to the continuous **O_2** or **CO_2** monitoring system must be kept on site and available for inspection during regular office hours.

III. Monitoring and/or Recordkeeping Requirements

1. The permittee shall maintain monthly records of the following information for each emissions unit:

a. The natural gas usage rate for each month (in standard cubic feet).

2. The permittee shall maintain monthly records of the following information for each emissions unit:

a. Hours of operation of the turbine

b. Hours of operation of the duct burners

c. Beginning after the first 12 calendar months of operation following issuance of this permit, the rolling, 12-month summation of the hours of operation.

Also, during the first 12 calendar months of operation following issuance of this permit, the permittee shall record the cumulative hours of operation for each calendar month.

3. The permittee shall operate and maintain existing equipment to continuously monitor and record NO_x from this emissions unit in units of the applicable standard. Such continuous monitoring and recording equipment shall comply with the requirements of the appropriate sections specified in 40 CFR Part 60.13 and 40 CFR Part 75.

The permittee shall maintain records of all data obtained by the continuous NO_x monitoring system including, but not limited to, parts per million NO_x on an instantaneous (one-minute) basis, emissions of NO_x in units of the applicable standard in the appropriate averaging period (e.g., hourly, hourly rolling, 3-hour, daily, 30-day rolling, etc.), results of daily zero/span calibration checks, and magnitude of manual calibration adjustments.

4. The permittee shall operate and maintain equipment to continuously monitor and record CO from this emissions unit in units of the applicable standard. Such continuous monitoring and recording equipment shall comply with the requirements specified in 40 CFR Part 60.13 .

The permittee shall maintain records of all data obtained by the continuous CO monitoring system including, but not limited to, parts per million CO on an instantaneous (one minute) basis, emissions of CO in units of the applicable standard in the appropriate averaging period (e.g., hourly, hourly rolling, 3-hour, daily, 30-day rolling, annual, etc.), results of daily zero/span calibration checks, and magnitude of manual calibration adjustments.

5. The permittee shall operate and maintain equipment to continuously monitor and record O_2 or CO_2 from this emissions unit in percent O_2 or CO_2. Such continuous monitoring and recording equipment shall comply with the requirements in the appropriate sections specified in 40 CFR Part 60.13 and 40 CFR Part 75.

The permittee shall maintain records of all data obtained by the continuous O_2 or CO_2 monitoring system including, but not limited to, percent O_2 or CO_2 on an instantaneous (one-minute) basis, emissions of O_2 or CO_2 in units of the applicable standard in the appropriate averaging period (e.g., hourly, hourly rolling, 3-hour, daily, 30-day rolling, etc.), results of daily zero/span calibration checks, and magnitude of manual calibration adjustments.

6. The permittee shall install, calibrate, operate, and maintain continuous monitoring systems to monitor and record the average hourly fuel consumption of the combustion turbine and duct burner. The fuel flow monitoring systems comply with the requirements of 40 CFR Part 75, Appendix D.

7. The permittee shall monitor the sulfur content and gross calorific value of the fuel being fired in the combustion turbine and duct burner. Fuel sampling and analysis shall be conducted according to the procedures and at the frequency specified by 40 CFR Part 75, Appendix D.

8. The permittee shall determine the hourly heat input rate to the combustion turbine and duct burner from the fuel flow rate as determined in term A.III.6 and fuel gross calorific value as determined in term A.III.7. The heat input rate shall be calculated in accordance with the procedures in Section 5 of 40 CFR Part 75, Appendix F.

9. The permittee shall maintain records of the following information for each emissions unit:

a. Number of startups, and the duration of each startup.

b. Number of shutdowns, and the duration of each shutdown.

10. The permittee shall maintain hourly records of the following information for this emissions unit:

in lb(s)/hr emissions rate for NO_x and CO as obtained from terms III.3. and 4. based upon an hourly averaging period as allowed in the appropriate sections of 40 CFR Part 60.

11. The permittee shall maintain monthly records of the following information for this emissions unit:

a. the operating hours;

b. during the first 12 calendar months of operation, the permittee shall record the cumulative operating hours for each calendar month; and

c. beginning after the first 12 calendar months of operation, the rolling, 12-month summation of the operating hours.

d. during the first 12 calendar months of operation, the cumulative NO_x and CO emissions, in tons (i.e., $\frac{\text{b x term 10}}{2{,}000}$, for each pollutant); and

f. beginning after the first 12 calendar months of operation, the rolling, 12-month NO_x and CO emissions, in tons (i.e., $\frac{\text{c x term 10}}{2{,}000}$, for each pollutant).

12. PSD REQUIREMENTS

The source described in this Permit to Install is subject to the applicable provisions of the Prevention of Significant Deterioration (PSD) regulations as promulgated by the United States Environmental Protection Agency 40 CFR 52.21. The authority to apply and enforce the PSD regulations has been delegated to the Ohio Environmental Protection Agency. The terms and conditions of this permit and the requirements of the PSD regulations are also enforceable by the United States Environmental Protection Agency.

In accordance with 40 CFR 124.15, 124.19 and 124.20, the following shall apply: (1) the effective date of this permit shall be 30 days after the service of notice to any public commentors of the final decision to issue, modify, or revoke and re-issue the permit, unless the service of notice is by mail, in which case the effective date of the permit shall be 33 days after the service of notice; and (2) if an appeal is made to the Environmental Appeals Board of the United States Environmental Protection Agency, the effective date of the permit is suspended until such time as the appeal is resolved or denied.

Appeals will be addressed to:

United States Environmental Protection Agency
Environmental Appeals Board
401 M Street, SW (MC-113do)
Washington, DC 20460

IV. Reporting Requirements

1. The permittee shall submit deviation (excursion) reports that identify each day when a fuel other than natural gas was burned in this emissions unit. Each report shall be submitted within 30 days after the deviation occurred.

2. The permittee shall submit deviation (excursion) reports which identify all exceedances of the rolling, 12-month operating hours limitation and, for the first 12 calendar months of operation, all exceedances of the maximum allowable cumulative operating hours levels. These reports are due by the date described in Part 1 - General Terms and Conditions of this permit under section (A)(2).

3. Pursuant to OAC rules 3745-15-04, 3745-35-02, and ORC sections 3704.03(I) and 3704.031 and 40 CFR Parts 60.7 and 60.13(h), the permittee shall submit reports within 30 days following the end of each calendar quarter to the appropriate Ohio EPA District Office or local air agency documenting the date, commencement and completion times, duration, magnitude, reason (if known), and corrective actions taken (if any), of all instances of NO_x values in excess of the applicable limits specified in 40 CFR Part 76 and any limitations specified in the terms and conditions of this permit or variance. These reports shall also contain the total NO_x emissions for the calendar quarter (in tons).

The permittee shall submit reports within 30 days following the end of each calendar quarter to the appropriate Ohio EPA District Office or local air agency documenting any continuous NO_x monitoring system downtime while the emissions unit was on line (date, time, duration and reason) along with any corrective action(s) taken. The permittee shall provide the emissions unit operating time during the reporting period and the date, time, reason and corrective action(s) taken for each time period of emissions unit and control equipment malfunctions. The total operating time of the emissions unit and the total operating time of the analyzer while the emissions unit was on line shall also be included in the quarterly report.

If there are no excess emissions during the calendar quarter, the permittee shall submit a statement to that effect along with the emissions unit operating time during the reporting period and the date, time, reason, and corrective action(s) taken for each time period of emissions unit, control equipment, and/or monitoring system malfunctions. The total operating time of the emissions unit and the total operating time of the analyzer while the emissions unit was on line also shall be included in the quarterly report. These quarterly excess emission reports shall be submitted by January 30, April 30, July 30, and October 30 of each year and shall address the data obtained during the previous calendar quarter.

4. Pursuant to OAC rules 3745-15-04, 3745-35-02, and ORC sections 3704.03(I) and 3704.031, the permittee shall submit a summary of the excess emission report pursuant to 40 CFR Part 60.7. The summary shall be submitted to the appropriate Ohio EPA District Office or local air agency within 30 days following the end of each calendar quarter in a manner prescribed by the Director.

5. Pursuant to OAC rules 3745-15-04, 3745-35-02, and ORC sections 3704.03(I) and 3704.031 and 40 CFR Parts 60.7 and 60.13(h), the permittee shall submit reports within 30 days following the end of each calendar quarter to the appropriate Ohio EPA District Office or local air agency

documenting the date, commencement and completion times, duration, magnitude, reason (if known), and corrective actions taken (if any) of all instances of **CO** values in excess of any applicable limitation(s) specified in OAC Chapter 3745-21, 40 CFR Part 60, or any limitation(s) specified in the terms and conditions of this permit, in units of the standard. These reports shall also contain the total **CO** emissions for the calendar quarter (in tons).

The permittee shall submit reports within 30 days following the end of each calendar quarter to the appropriate Ohio EPA District Office or local air agency documenting any continuous **CO** monitoring system downtime while the emissions unit was on line (date, time, duration and reason) along with any corrective action(s) taken. The permittee shall provide the emissions unit operating time during the reporting period and the date, time, reason and corrective action(s) taken for each time period of emissions unit and control equipment malfunctions. The total operating time of the emissions unit and the total operating time of the analyzer while the emissions unit was on line shall also be included in the quarterly report.

If there are no excess emissions during the calendar quarter, the permittee shall submit a statement to that effect along with the emissions unit operating time during the reporting period and the date, time, reason, and corrective action(s) taken for each time period of emissions unit, control equipment, and/or monitoring system malfunctions. The total operating time of the emissions unit and the total operating time of the analyzer while the emissions unit was on line shall also be included in the quarterly report. These quarterly excess emission reports shall be submitted by January 30, April 30, July 30, and October 30 of each year and shall address the data obtained during the previous calendar quarter.

6. Pursuant to 40 CFR Parts 60.7 and 60.13(h), the permittee shall submit reports within 30 days following the end of each calendar quarter to the appropriate Ohio EPA District Office or local air agency documenting all instances of continuous **O_2** or **CO_2** monitoring system downtime while the emissions unit was on line (date, time, duration and reason) along with any corrective action(s) taken. The permittee shall provide the emissions unit operating time during the reporting period and the date, time, reason and corrective action(s) taken for each time period of emissions unit malfunctions. The total operating time of the emissions unit and the total operating time of the analyzer while the emissions unit was on line shall be included in the quarterly report. These quarterly reports shall be submitted by January 30, April 30, July 30, and October 30 of each year and shall address the data obtained during the previous calendar quarter.

7. The permittee shall submit deviation (excursion) reports that identify any record which shows that the sulfur content of the natural gas exceeded 2 grains per standard cubic foot. These reports are due by the date described in Part I - General Terms and Conditions of this permit under section (A)(2).

8. The permittee shall submit deviation (excursion) reports that identify each time when this emissions unit was not in compliance with the requirements of condition II.3. above. These reports are due by the date described in Part I - General Terms and Conditions of this permit under section (A)(2).

9. In lieu of the excess emissions reports required under 40 CFR Part 60.334, the permittee shall submit excess emissions reports for emissions unit P001 in accordance with this permit.

10. This emissions unit is subject to the applicable provisions of Subpart Da. and GG of the New Source Performance Standards (NSPS) as promulgated by the United States Environmental Protection Agency, 40 CFR Part 60. The application and enforcement of these standards are delegated to the Ohio EPA. The requirements of 40 CFR Part 60 are also federally enforceable.

Pursuant to 40 CFR Part 60.7, the permittee is hereby advised of the requirement to report the following at the appropriate times:

a. construction date (no later than 30 days after such date);

b. anticipated start-up date (not more than 60 days or less than 30 days prior to such date);

c. actual start-up date (within 15 days after such date); and,

d. date of performance testing (if required, at least 30 days prior to testing).

Reports are to be sent to:

Ohio Environmental Protection Agency
DAPC - Permit Management Unit
P. O. Box 163669
Columbus, Ohio 43216-3669

and

Ohio Environmental Protection Agency
Southeast District Office
Division of Air Pollution Control
2195 Front Street
Logan, Ohio 43138

V. Testing Requirements

1. The permittee shall conduct, or have conducted, emission testing for this emissions unit in accordance with the following requirements:

a. The emission testing shall be conducted within 60 days after achieving the maximum production rate at which the emissions unit will be operated, but not later than 180 days after initial startup of such emissions unit.

b. The emission testing shall be conducted to demonstrate compliance with the NO_x and CO outlet concentration, and the mass emissions limitations for NO_x,* CO, Formaldehyde, VOC and PM.

c. The following test method(s) shall be employed to demonstrate compliance with the above emissions limitations: for NO_x, Method 20 of 40 CFR Part 60, Appendix A; for PM, Method 5 of 40 CFR Part 60, Appendix A; for Formaldehyde, SW-846 Method 0011; for VOC Method 25 of 40 CFR Part 60, Appendix A; and for CO Method 10 of 40 CFR Part 60, Appendix A. Alternative U.S. EPA approved test methods may be used with prior approval from the Ohio EPA.

d. The testing shall be conducted while the emissions unit is operating at or near its maximum capacity with and without duct burner firing, unless otherwise specified or approved by Ohio EPA or local air agency.

e. Not later than 30 days prior to the proposed test date(s), the permittee shall submit an "Intent to Test" notification to the Ohio EPA, Southeast District Office. The "Intent to Test" notification shall describe in detail the proposed test methods and procedures, the emissions unit operating parameters, the time(s) and date(s) of the test(s), and the person(s) who will be conducting the test(s). Failure to submit such notification for review and approval prior to the test(s) may result in the Ohio EPA, Southeast District Office refusal to accept the results of the emission test(s).

f. Personnel from the Ohio EPA, Southeast District Office shall be permitted to witness the test(s), examine the testing equipment, and acquire data and information necessary to ensure that the operation of the emissions unit and the testing procedures provide a valid characterization of the emissions from the emissions unit and/or the performance of the control equipment.

g. A comprehensive written report on the results of the emissions test(s) shall be signed by the person or persons responsible for the tests and submitted to the Ohio EPA, Southeast District Office within 30 days following completion of the test(s). The permittee may request additional time for the submittal of the written report, where warranted, with prior approval from the Ohio EPA, Southeast District Office.

* Using the test methods and procedures required under 40 CFR Part 60.335.

2. Compliance with the allowable emission limitations in this permit shall be determined according to the following methods:

a. <u>Emission Limitation</u>

NO_x emissions shall not exceed 3.5 ppmvd at 15% Oxygen
24.7 lbs/hr without duct burner firing
32.3 lbs/hr with duct burner firing
157.5 tons per year, which includes 32.2 tons for startups and shutdowns

Applicable Compliance Method

Initial compliance with the allowable outlet concentration, and the lbs/hr emission limitations shall be demonstrated by the performance testing as described in condition V.1 and continual compliance with those limitations shall be demonstrated by the use of the CEM in condition III.3. based upon an hourly averaging period as allowed in 40 CFR Part 60. Compliance with the annual emission limitation shall be determined by the record keeping required in condition III. 1., 2., and 3. The annual emissions associated with start-up and shut-down shall be demonstrated by the record keeping required in condition III. 9. using the lbs/ start-up and shut-down values in condition III.3.

b. Emission Limitation

PM emissions shall not exceed
19.0 lbs/hr without duct burner firing
28.0 lbs/hr with duct burner firing
103.5 tons per year

Applicable Compliance Method

Compliance with the lbs/hr emission limitations shall be demonstrated by the performance testing in condition V.1. Compliance with the annual emission limitation shall be determined by multiplying the hourly emission rate by the actual annual hours of operation and dividing by 2000 lbs/ton.

c. Emission Limitation

SO2 emissions shall not exceed
11.2 lbs/hr without duct burner firing
14.5 lbs/hr with duct burner firing
56.5 tons per year

Applicable Compliance Method

Compliance with the hourly emission limitation shall be determined by the record keeping required in condition III. 1., 2., and 8. If required, the permittee shall demonstrate compliance by emission testing in accordance with approved US EPA test methods. Compliance with the annual emission limitation shall be determined by multiplying the

hourly emission rate by the actual annual hours of operation and dividing by 2000 lbs/ton.

d. Emission Limitation

VOC emissions shall not exceed
3.0 lbs/hr without duct burner firing
19.6 lbs/hr with duct burner firing
63.1 tons per year, which includes 12.6 tons for startups and shutdowns

Applicable Compliance Method

Compliance with the lbs/hr limitations shall be demonstrated by the performance testing in condition V.1. Compliance with the annual emission limitation shall be determined by multiplying the hourly emission rate by the actual annual hours of operation and dividing by 2000 lbs/ton. The annual emissions associated with start-up and shut-down shall be determined by the record keeping required in condition III. 9. using the lbs/ start-up and shut-down values in condition III.3.

e. Emission Limitation

CO emissions shall not exceed
10 ppmvd at 15% Oxygen without duct burner firing
14 ppmvd at 15% Oxygen with duct burner firing
43.0 lbs/hr without duct burner firing
78.0 lbs/hr with duct burner firing
453.7 tons per year, which includes 186.6 tons for startups and shutdowns

Applicable Compliance Method

Initial compliance with the allowable outlet concentration, and the lbs/hr emission limitations shall be demonstrated by the performance testing as described in condition V.1 and continual compliance with those limitations shall be demonstrated by the use of the CEM in condition III.4. based upon an hourly averaging period as allowed in 40 CFR Part 60. Compliance with the annual emission limitation shall be determined by the record keeping required in condition III. 1., 2., and 4. The annual emissions associated with start-up and shut-down shall be determined by the record keeping required in condition III. 9. using the lbs/ start-up and shut-down values in condition III.3.

f. Emission Limitation

ammonia (NH3) emissions shall not exceed
26.6 lbs/hr without duct burner firing
34.6 lbs/hr with duct burner firing
134.5 tons per year

Applicable Compliance Method

Compliance with the lbs/hr emission limitation shall be demonstrated by multiplying the emission factor of 0.0136 pound of ammonia/MMBtu heat input (emission factor supplied by the permittee) by the maximum Btu rating. If required, the permittee shall demonstrate compliance by emission testing in accordance with approved US EPA test methods. Compliance with the annual emission limitation shall be determined by multiplying the hourly emission rate by the actual annual hours of operation and dividing by 2000 lbs/ton.

g. Emission Limitation

Formaldehyde emissions shall not exceed
0.8 lbs/hr without duct burner firing
0.82 lbs/hr with duct burner firing
3.6 tons per year
Applicable Compliance Method

Compliance with the lbs/hr emission limitations shall be demonstrated by the performance testing in condition V.1. Compliance with the annual emission limitation shall be determined by multiplying the hourly emission rate by the actual annual hours of operation and dividing by 2000 lbs/ton.

h. Emission Limitation

Sulfuric acid (H2SO4) emissions shall not exceed
1.7 lbs/hr without duct burner firing
2.2 lbs/hr with duct burner firing
8.6 tons per year

Applicable Compliance Method

Compliance with the lb/hr emission limitation shall be demonstrated by multiplying the emission factor of 0.0017 pound of sulfuric acid/MM Btu heat input (emission factor supplied by the permittee) by the maximum Btu rating. If required, the permittee shall demonstrate compliance by emission testing in accordance with approved US EPA test

methods. Compliance with the annual emission limitation shall be determined by multiplying the hourly emission rate by the actual annual hours of operation and dividing by 2000 lbs/ton.

i. Emission Limitation

Visible particulate emissions from any stack shall not exceed 10 percent opacity as a six-minute average.

Applicable Compliance Method

Compliance with the visible emissions limitation established by this permit shall be determined by Method 9, 40 CFR Part 60 Appendix A.

VI. Miscellaneous Requirements

1. In accordance with good engineering practices, the SCR unit on emissions unit P001 shall be installed, operated and maintained in accordance with the manufacturer's recommendations, with any modifications deemed necessary by the permittee. The permittee shall maintain on site a copy of the operation & maintenance manual, as provided by the manufacturer.

B. State Only Enforceable Section

I. Applicable Emissions Limitations and/or Control Requirements

1. The specific operations(s), property, and/or equipment which constitute this emissions unit are listed in the following table along with the applicable rules and/or requirements and with the applicable emissions limitations and/or control measures. Emissions from this unit shall not exceed the listed limitations, and the listed control measures shall be specified in narrative form following the table.

Operations, Property, and/or Equipment	Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
P001 - 170 MW GE 7FA natural gas-fired dry low NOx (DLN) combustion turbine with duct firing operating in combined cycle mode controlled by Selective Catalytic Reduction (SCR)	NONE	NONE

2. Additional Terms and Conditions

2.a NONE

II. Operational Restrictions

NONE

III. Monitoring and/or Recordkeeping Requirements

NONE

IV. Reporting Requirements

NONE

V. Testing Requirements

NONE

VI. Miscellaneous Requirements

NONE

Part III - SPECIAL TERMS AND CONDITIONS FOR SPECIFIC EMISSIONS UNIT(S)

A. State and Federally Enforceable Section

I. Applicable Emissions Limitations and/or Control Requirements

1. The specific operations(s), property, and/or equipment which constitute this emissions unit are listed in the following table along with the applicable rules and/or requirements and with the applicable emissions limitations and/or control measures. Emissions from this unit shall not exceed the listed limitations, and the listed control measures shall be specified in narrative form following the table.

Operations, Property, and/or Equipment	Applicable Rules/Requirements	
P002 - 170 MW GE 7FA natural gas-fired dry low NOx (DLN) combustion turbine with duct firing operating in combined cycle mode controlled by Selective Catalytic Reduction (SCR)	OAC Rule 3745-31-05 (A)(3)	
	OAC Rule 3745-31-05 (A)(3)	OAC Rule 3745-31-05 (A)(3)

		40 CFR Part 75 OAC rule 3745-103
OAC Rule 3745-31-05 (A)(3)		
	40 CFR part 60, Subpart GG 40 CFR part 60, Subpart Da	
OAC Rule 3745-31-05 (A)(3)	OAC rule 3745-18-06(F) OAC Rule 3745-17-11 (B)(4) OAC Rule 3745-17-07(A) 40 CFR 52.21 OAC rule 3745-31- (13) thru (20)	

Applicable Emissions Limitations/Control Measures		
The requirements of this rule also include compliance with the requirements of 40 CFR 60 Subpart GG, OAC rule 3745-18-06(F), 3745-17-11(B)(4), OAC rule 3745-17-07(A), 40 CFR 52.21, and OAC 3745-31-(13) thru (20).	shall not exceed 26.6 lbs/hr formaldehyde emissions shall not exceed 0.8 lbs/hr sulfuric acid emissions shall not exceed 1.7 lbs/hr	sulfuric acid emissions shall not exceed 2.2 lbs/hr **STARTUP AND SHUTDOWN EMISSIONS** (also see A.II.3.) nitrogen oxides (NO_x) emissions shall not exceed 32.2 tons per year carbon monoxide (CO) emissions shall not exceed 186.6 tons per year volatile organic compounds (VOC) emissions shall not exceed 12.6 tons per year
EMISSION LIMITS WITHOUT DUCT BURNER FIRING nitrogen oxides (NO_x) emissions shall not exceed 3.5 ppmvd at 15% Oxygen and 24.7 lbs /hr PM emissions shall not exceed 19.0 lbs/hr sulfur dioxide (SO_2) shall not exceed 11.2 lbs/hr carbon monoxide (CO) emissions shall not exceed 10 ppmvd at 15% Oxygen and 43.0 lbs/hr volatile organic compounds (VOC) emissions shall not exceed 3.0 lbs/hr ammonia (NH3) emissions	**EMISSION LIMITS WITH DUCT BURNER FIRING (limited to 4,500 hours per year)** nitrogen oxides (NO_x) emissions shall not exceed 3.5 ppmvd at 15% Oxygen and 32.3 lbs /hr PM emissions shall not exceed 28.0 lbs/hr sulfur dioxide (SO_2) shall not exceed 14.5 lbs/hr carbon monoxide (CO) emissions shall not exceed 14 ppmvd at 15% Oxygen and 78.0 lbs/hr volatile organic compounds (VOC) emissions shall not exceed 19.6 lbs/hr ammonia (NH3) emissions shall not exceed 34.6 lbs/hr formaldehyde emissions shall not exceed 0.82 lbs/hr	**TOTAL TONS PER YEAR** (including 4,260 hours per year without duct burners, 4,500 hours per year with duct burners, startups, and shutdowns) nitrogen oxides (NO_x) emissions shall not exceed 157.5 tons per year PM emissions shall not exceed 103.5 tons per year sulfur dioxide (SO_2) shall not exceed 56.5 tons per year carbon monoxide (CO) emissions shall not exceed 453.7 tons per year volatile organic compounds (VOC) emissions shall not exceed

63.1 tons per year	VOC - 63.1 H2SO4 - 8.6
ammonia (NH3) emissions shall not exceed 134.5 tons per year	See A.I.2.c.
formaldehyde emissions shall not exceed 3.6 tons per year	See A.I.2.c.
sulfuric acid emissions shall not exceed 8.6 tons per year	
Visible particulate emissions from any stack shall not exceed 10 percent opacity as a six-minute average	
operational restriction, see II. 1.	
see A.2.b.	
see A.2.a.	
see A.2.a.	
see A.2.a.	
see A.2.a.	
The tons per rolling 12-month period shall not exceed : NOx - 157.5 SO2 - 56.5 PM - 103.5 CO - 453.7	

2. Additional Terms and Conditions

2.a The emissions limit based on this applicable rule is equivalent to or less stringent than the limit established pursuant to OAC rule 3745-31-05.

2.b The emissions limits based on this applicable rule are equivalent to or less stringent than the limits established pursuant to OAC rule 3745-31-05. Except as provided for in the terms and conditions in this permit, the permittee is not exempt from meeting any additional requirements of 40 CFR Part 60, Subpart GG.

2.c If the permittee is subject to the requirements of 40 CFR Part 75 concerning acid rain, the permittee shall ensure that any effected emissions unit complies with those requirements. Emissions exceeding any allowances that are lawfully held under Title IV of the Act, or any regulations adopted thereunder, are prohibited.

II. Operational Restrictions

1. The permittee shall burn only natural gas in this emissions unit. The maximum sulfur content of the natural gas shall not exceed 2 grains per 100 standard cubic feet.

2. The permit to install for this emissions unit (P001) was evaluated based actual materials (typical coatings and clean up materials) and the design parameters of the emissions unit's exhaust system, as specified by the permittee in the air permit to install application. The Ohio EPA's "Review of New Sources of Air Toxic Emissions" policy (Air Toxic Policy") was applied for each pollutant emitted by this emissions unit using data from the permit to install application and the SCREEN 3.0 model (or other Ohio EPA approved model). The predicted 1-hour maximum ground-level concentration to the Maximum Acceptable Ground-Level Concentration (MAGLC). The following summarizes the results of the modeling:

Pollutant: Formaldehyde
TLV (ug/m3): 273 (Converted from the STEL)
Maximum Hourly Emission Rate (lbs/hr): 1.64*
Predicted 1-Hour Maximum Ground-Level Concentration (ug/m3): 0.23
MAGLC (ug/m3): 6.49

Pollutant: Sulfuric Acid
TLV (ug/m3): 1000
Maximum Hourly Emission Rate (lbs/hr): 4.4*
Predicted 1-Hour Maximum Ground-Level Concentration (ug/m3): 2.5
MAGLC (ug/m3): 23.8

Pollutant: Ammonia
TLV (ug/m3): 17000
Maximum Hourly Emission Rate (lbs/hr): 69.2*
Predicted 1-Hour Maximum Ground-Level Concentration (ug/m3): 39.2
MAGLC (ug/m3): 404.8

* This was modeled for emissions units P001 & P002 combined.

Physical changes to or changes in the method of operation of the emissions unit after its installation or modification could affect the parameters used to determine whether or not the "Air Toxic Policy" is satisfied. Consequently, prior to making a change that could impact such parameters, the permittee shall conduct an evaluation to determine that the "Air Toxic Policy" will still be still satisfied. If, upon evaluation, the permittee determines that the "Air Toxic Policy" will not be satisfied, the permittee will not make the change. Changes that can affect the parameters used in applying the "Air Toxic Policy" include the following:

a. changes in the composition of the materials used, or the use of new materials, that would result in the emission of a compound with a lower Threshold Limit Value (TLV), as indicated in the most recent version of the handbook entitled "American Conference of Governmental Industrial Hygienists (ACGIH)," than the lowest TLV value specified in the above table;

b. changes in the composition of the materials, or use of new materials, that would result in an increase in emissions of any pollutant with a listed TLV that was proposed in the application and modeled; and

c. physical changes to the emissions unit or its exhaust parameters (e.g., increased/ decreased exhaust flow, changes in stack height, changes in stack diameter, etc.).

If the permittee determines that the "Air Toxic Policy" will be satisfied for the above changes, the Ohio EPA will not consider the change(s) to be a "modification" under OAC rule 3745-31-01(VV)(1)(a)(ii), and a modification of the existing permit to install will not be required. If the change(s) is (are) defined as a modification under other provisions of the modification definition (other than (VV)(1)(a)(ii)), then the permittee shall obtain a final permit to install prior to the change.

The permittee shall collect, record, and retain the following information when it conducts evaluations to determine that the changed emissions unit will still satisfy the "Air Toxic Policy:"

a. a description of the parameters changed (composition of materials, new pollutants emitted, change in stack/exhaust parameters, etc.);

b. documentation of its evaluation and determination that the changed emissions unit still satisfies the "Air Toxic Policy"; and

c. where computer modeling is performed, a copy of the resulting computer model runs that show the results of the application of the "Air Toxic Policy" for the change.

3. Startup and Shut down shall be defined as when the unit is running at less than 50% of electric load, but under no circumstances shall startups exceed 250 minutes in duration and shutdowns shall not exceed 2 hours in duration. Startup and shutdowns shall be limited to 260 cycles(one startup and one shutdown) per year. Each start up and shutdowns shall be limited to the following:

Pollutant	lbs/start up	lbs/shut down	total lbs/startup and one shutdown
NOx	212.7	35	247.7
CO	1,174	261.5	1435.5
VOC	84.7	12	96.7

4. The maximum annual hours of operation of the duct burners for emissions unit P002 shall not exceed 4,500 hours, based upon a rolling, 12-month summation.

To ensure enforceability during the first 12 calendar months following the startup of this emissions unit the permittee shall not exceed the monthly hours of operation restrictions specified in the following table:

Month	Cumulative hours of Operation
1	720
1-2	1440
1-3	2160
1-4	2880
1-5	3600
1-6	4320
1-7	4500
1-8	4500
1-9	4500
1-10	4500
1-11	4500
1-12	4500

After the first 12 calendar months following the startup of emissions unit P002, compliance with the annual hours of operation restriction shall be based on a rolling, 12-month summation.

5. Continuous **NOx** Monitoring - Certified Systems
Statement of Certification

Prior to the installation of the continuous ***NO_x*** monitoring system, the permittee shall submit information detailing the proposed location of the sampling site in accordance with the siting requirements in 40 CFR Part 60, Appendix B, Performance Specification 6 for approval by the Ohio EPA, Central Office.

Within 60 days after achieving the maximum production rate at which the emissions unit will be operated, but not later than 180 days after initial startup of such emissions unit, the permittee shall conduct certification tests of such equipment pursuant to the appropriate sections of ORC section 3704.03(I), 40 CFR Part 60, Appendix B, Performance Specification 6, and 40 CFR Part 75. Personnel from the appropriate Ohio EPA District Office or local air agency shall be notified 30 days prior to initiation of the applicable tests and shall be permitted to examine equipment and witness the certification tests. In accordance with OAC rule 3745-15-04, all copies of the test results shall be submitted to the appropriate Ohio EPA District Office or local air agency within 30 days after the test is completed. Copies of the test results shall be sent to the appropriate Ohio EPA District Office or local air agency and the Ohio EPA, Central Office. Certification of the continuous ***NO_x*** monitoring system shall be granted upon determination by the Ohio EPA, Central Office that the system meets all requirements of the appropriate sections of ORC section 3704.03(I), 40 CFR Part 60, Appendix B, Performance Specification 6 and 40 CFR Part 75.

6. Within 180 days of the effective date of this permit, the permittee shall develop a written quality assurance/quality control plan for the continuous NO_x monitoring system designed to ensure continuous valid and representative readings of NO_x emissions in units of the applicable standard. The plan shall follow the requirements of the appropriate sections of 40 CFR Part 60, Appendix F and 40 CFR Part 75, Appendix B. The quality assurance/quality control plan and a logbook dedicated to the continuous NO_x monitoring system must be kept on site and available for inspection during regular office hours.

7. Continuous **CO** Monitoring - Certified Systems
Statement of Certification

Prior to the installation of the continuous ***CO*** monitoring system, the permittee shall submit information detailing the proposed location of the sampling site in accordance with the siting requirements in 40 CFR Part 60, Appendix B, Performance Specification 4 and 6 for approval by the Ohio EPA, Central Office.

Within 60 days after achieving the maximum production rate at which the emissions unit will be operated, but not later than 180 days after initial startup of such emissions unit, the permittee shall conduct certification tests of the continuous **CO** monitoring system pursuant to ORC section 3704.03(I), 40 CFR Part 60, Appendix B, Performance Specification 4 and 6. Personnel from the appropriate Ohio EPA District Office or local air agency shall be notified 30 days prior to initiation of the applicable tests and shall be permitted to examine equipment and witness the

certification tests. In accordance with OAC rule 3745-15-04, all copies of the test results shall be submitted to the appropriate Ohio EPA District Office or local air agency within 30 days after the test is completed. Copies of the test results shall be sent to the appropriate Ohio EPA District Office or local air agency and the Ohio EPA, Central Office. Certification of the continuous **CO** monitoring system shall be granted upon determination by the Ohio EPA Central Office that the system meets all requirements of ORC section 3704.03(I) and 40 CFR Part 60, Appendix B, Performance Specification 4 and 6.

8. Within 180 days of the effective date of this permit, the permittee shall develop a written quality assurance/quality control plan for the continuous **CO** monitoring system designed to ensure continuous valid and representative readings of **CO**. The plan shall follow the requirements of 40 CFR Part 60, Appendix F. The quality assurance/quality control plan and a logbook dedicated to the continuous **CO** monitoring system must be kept on site and available for inspection during regular office hours.

9. Continuous O_2 or CO_2 Monitoring - Certified Systems
Statement of Certification

Prior to the installation of the continuous O_2 or CO_2 monitoring system, the permittee shall submit information detailing the proposed location of the sampling site in accordance with the siting requirements in 40 CFR Part 60, Appendix B, Performance Specification 3 for approval by the Ohio EPA, Central Office.

Within 60 days after achieving the maximum production rate at which the emissions unit will be operated, but not later than 180 days after initial startup of such emissions unit, the permittee shall conduct certification tests of such equipment pursuant to the appropriate sections of ORC section 3704.03(I), 40 CFR Part 60, Appendix B, Performance Specification 3, and 40 CFR Part 75. Personnel from the appropriate Ohio EPA District Office or local air agency shall be notified 30 days prior to initiation of the applicable tests and shall be permitted to examine equipment and witness the certification tests. In accordance with OAC rule 3745-15-04, all copies of the test results shall be submitted to the appropriate Ohio EPA District Office or local air agency within 30 days after the test is completed. Copies of the test results shall be sent to the appropriate Ohio EPA District Office or local air agency and the Ohio EPA, Central Office. Certification of the continuous O_2 or CO_2 monitoring system shall be granted upon determination by the Ohio EPA, Central Office that the system meets all requirements of the appropriate sections of ORC section 3704.03(I), 40 CFR Part 60, Appendix B, Performance Specification 3 and 40 CFR Part 75.

10. Within 180 days of the effective date of this permit, the permittee shall develop a written quality assurance/quality control plan for the continuous O_2 or CO_2 monitoring system designed to ensure continuous valid and representative readings of O_2 or CO_2 emissions in units of the applicable standard. The plan shall follow the requirements of the appropriate sections of 40 CFR

Part 60, Appendix F and 40 CFR Part 75, Appendix B. The quality assurance/quality control plan and a logbook dedicated to the continuous O_2 or CO_2 monitoring system must be kept on site and available for inspection during regular office hours.

III. Monitoring and/or Recordkeeping Requirements

1. The permittee shall maintain monthly records of the following information for each emissions unit:

a. The natural gas usage rate for each month (in standard cubic feet).

2. The permittee shall maintain monthly records of the following information for each emissions unit:

a. Hours of operation of the turbine

b. Hours of operation of the duct burners

c. Beginning after the first 12 calendar months of operation following issuance of this permit, the rolling, 12-month summation of the hours of operation.

Also, during the first 12 calendar months of operation following issuance of this permit, the permittee shall record the cumulative hours of operation for each calendar month.

3. The permittee shall operate and maintain existing equipment to continuously monitor and record NO_x from this emissions unit in units of the applicable standard. Such continuous monitoring and recording equipment shall comply with the requirements of the appropriate sections specified in 40 CFR Part 60.13 and 40 CFR Part 75.

The permittee shall maintain records of all data obtained by the continuous NO_x monitoring system including, but not limited to, parts per million NO_x on an instantaneous (one-minute) basis, emissions of NO_x in units of the applicable standard in the appropriate averaging period (e.g., hourly, hourly rolling, 3-hour, daily, 30-day rolling, etc.), results of daily zero/span calibration checks, and magnitude of manual calibration adjustments.

4. The permittee shall operate and maintain equipment to continuously monitor and record CO from this emissions unit in units of the applicable standard. Such continuous monitoring and recording equipment shall comply with the requirements specified in 40 CFR Part 60.13 .

The permittee shall maintain records of all data obtained by the continuous CO monitoring system including, but not limited to, parts per million CO on an instantaneous (one minute) basis, emissions of CO in units of the applicable standard in the appropriate averaging period (e.g., hourly, hourly rolling, 3-hour, daily, 30-day rolling, annual, etc.), results of daily zero/span calibration checks, and magnitude of manual calibration adjustments.

5. The permittee shall operate and maintain equipment to continuously monitor and record **O_2** or **CO_2** from this emissions unit in percent **O_2** or **CO_2**. Such continuous monitoring and recording equipment shall comply with the requirements of the appropriate sections specified in 40 CFR Part 60.13 and 40 CFR Part 75.

The permittee shall maintain records of all data obtained by the continuous **O_2** or **CO_2** monitoring system including, but not limited to, percent **O_2** or **CO_2** on an instantaneous (one-minute) basis, emissions of **O_2** or **CO_2** in units of the applicable standard in the appropriate averaging period (e.g., hourly, hourly rolling, 3-hour, daily, 30-day rolling, etc.), results of daily zero/span calibration checks, and magnitude of manual calibration adjustments.

6. The permittee shall install, calibrate, operate, and maintain continuous monitoring systems to monitor and record the average hourly fuel consumption of the combustion turbine and duct burner. The fuel flow monitoring systems comply with the requirements of 40 CFR Part 75, Appendix D.

7. The permittee shall monitor the sulfur content and gross calorific value of the fuel being fired in the combustion turbine and duct burner. Fuel sampling and analysis shall be conducted according to the procedures and at the frequency specified by 40 CFR Part 75, Appendix D.

8. The permittee shall determine the hourly heat input rate to the combustion turbine and duct burner from the fuel flow rate as determined in term A.III.6 and fuel gross calorific value as determined in term A.III.7. The heat input rate shall be calculated in accordance with the procedures in Section 5 of 40 CFR Part 75, Appendix F.

9. The permittee shall maintain records of the following information for each emissions unit:

a. Number of startups, and the duration of each startup.

b. Number of shutdowns, and the duration of each shutdown.

10. The permittee shall maintain hourly records of the following information for this emissions unit:

in lb(s)/hr emissions rate for NO_x and CO as obtained from terms III.3. and 4. based upon an hourly averaging period as allowed in the appropriate sections of 40 CFR Part 60.

11. The permittee shall maintain monthly records of the following information for this emissions unit:

a. the operating hours;

b. during the first 12 calendar months of operation, the permittee shall record the cumulative operating hours for each calendar month; and

c. beginning after the first 12 calendar months of operation, the rolling, 12-month summation

of the operating hours.

d. during the first 12 calendar months of operation, the cumulative NO_x and CO emissions, in tons (i.e., b x term 10, for each pollutant); and
2,000

e. beginning after the first 12 calendar months of operation, the rolling, 12-month NO_x and CO emissions, in tons (i.e., c x term 10, for each pollutant).
2,000

12. PSD REQUIREMENTS

The source described in this Permit to Install is subject to the applicable provisions of the Prevention of Significant Deterioration (PSD) regulations as promulgated by the United States Environmental Protection Agency 40 CFR 52.21. The authority to apply and enforce the PSD regulations has been delegated to the Ohio Environmental Protection Agency. The terms and conditions of this permit and the requirements of the PSD regulations are also enforceable by the United States Environmental Protection Agency.

In accordance with 40 CFR 124.15, 124.19 and 124.20, the following shall apply: (1) the effective date of this permit shall be 30 days after the service of notice to any public commentors of the final decision to issue, modify, or revoke and re-issue the permit, unless the service of notice is by mail, in which case the effective date of the permit shall be 33 days after the service of notice; and (2) if an appeal is made to the Environmental Appeals Board of the United States Environmental Protection Agency, the effective date of the permit is suspended until such time as the appeal is resolved or denied.

Appeals will be addressed to:

United States Environmental Protection Agency
Environmental Appeals Board
401 M Street, SW (MC-113do)
Washington, DC 20460

IV. Reporting Requirements

1. The permittee shall submit deviation (excursion) reports that identify each day when a fuel other than natural gas was burned in this emissions unit. Each report shall be submitted within 30 days after the deviation occurred.

2. The permittee shall submit deviation (excursion) reports which identify all exceedances of the

rolling, 12-month operating hours limitation and, for the first 12 calendar months of operation, all exceedances of the maximum allowable cumulative operating hours levels. These reports are due by the date described in Part 1 - General Terms and Conditions of this permit under section (A)(2).

3. Pursuant to OAC rules 3745-15-04, 3745-35-02, and ORC sections 3704.03(I) and 3704.031 and 40 CFR Parts 60.7 and 60.13(h), the permittee shall submit reports within 30 days following the end of each calendar quarter to the appropriate Ohio EPA District Office or local air agency documenting the date, commencement and completion times, duration, magnitude, reason (if known), and corrective actions taken (if any), of all instances of NO_x values in excess of the applicable limits specified in 40 CFR Part 76 and any limitations specified in the terms and conditions of this permit or variance. These reports shall also contain the total NO_x emissions for the calendar quarter (in tons).

The permittee shall submit reports within 30 days following the end of each calendar quarter to the appropriate Ohio EPA District Office or local air agency documenting any continuous NO_x monitoring system downtime while the emissions unit was on line (date, time, duration and reason) along with any corrective action(s) taken. The permittee shall provide the emissions unit operating time during the reporting period and the date, time, reason and corrective action(s) taken for each time period of emissions unit and control equipment malfunctions. The total operating time of the emissions unit and the total operating time of the analyzer while the emissions unit was on line shall also be included in the quarterly report.

If there are no excess emissions during the calendar quarter, the permittee shall submit a statement to that effect along with the emissions unit operating time during the reporting period and the date, time, reason, and corrective action(s) taken for each time period of emissions unit, control equipment, and/or monitoring system malfunctions. The total operating time of the emissions unit and the total operating time of the analyzer while the emissions unit was on line also shall be included in the quarterly report. These quarterly excess emission reports shall be submitted by January 30, April 30, July 30, and October 30 of each year and shall address the data obtained during the previous calendar quarter.

4. Pursuant to OAC rules 3745-15-04, 3745-35-02, and ORC sections 3704.03(I) and 3704.031, the permittee shall submit a summary of the excess emission report pursuant to 40 CFR Part 60.7. The summary shall be submitted to the appropriate Ohio EPA District Office or local air agency within 30 days following the end of each calendar quarter in a manner prescribed by the Director.

5. Pursuant to OAC rules 3745-15-04, 3745-35-02, and ORC sections 3704.03(I) and 3704.031 and 40 CFR Parts 60.7 and 60.13(h), the permittee shall submit reports within 30 days following the end of each calendar quarter to the appropriate Ohio EPA District Office or local air agency documenting the date, commencement and completion times, duration, magnitude, reason (if known), and corrective actions taken (if any) of all instances of **CO** values in excess of any applicable limitation(s) specified in OAC Chapter 3745-21, 40 CFR Part 60, or any limitation(s) specified in the terms and conditions of this permit, in units of the standard. These reports shall

also contain the total **CO** emissions for the calendar quarter (in tons).

The permittee shall submit reports within 30 days following the end of each calendar quarter to the appropriate Ohio EPA District Office or local air agency documenting any continuous **CO** monitoring system downtime while the emissions unit was on line (date, time, duration and reason) along with any corrective action(s) taken. The permittee shall provide the emissions unit operating time during the reporting period and the date, time, reason and corrective action(s) taken for each time period of emissions unit and control equipment malfunctions. The total operating time of the emissions unit and the total operating time of the analyzer while the emissions unit was on line shall also be included in the quarterly report.

If there are no excess emissions during the calendar quarter, the permittee shall submit a statement to that effect along with the emissions unit operating time during the reporting period and the date, time, reason, and corrective action(s) taken for each time period of emissions unit, control equipment, and/or monitoring system malfunctions. The total operating time of the emissions unit and the total operating time of the analyzer while the emissions unit was on line shall also be included in the quarterly report. These quarterly excess emission reports shall be submitted by January 30, April 30, July 30, and October 30 of each year and shall address the data obtained during the previous calendar quarter.

6. Pursuant to 40 CFR Parts 60.7 and 60.13(h), the permittee shall submit reports within 30 days following the end of each calendar quarter to the appropriate Ohio EPA District Office or local air agency documenting all instances of continuous **O_2** or **CO_2** monitoring system downtime while the emissions unit was on line (date, time, duration and reason) along with any corrective action(s) taken. The permittee shall provide the emissions unit operating time during the reporting period and the date, time, reason and corrective action(s) taken for each time period of emissions unit malfunctions. The total operating time of the emissions unit and the total operating time of the analyzer while the emissions unit was on line shall be included in the quarterly report. These quarterly reports shall be submitted by January 30, April 30, July 30, and October 30 of each year and shall address the data obtained during the previous calendar quarter.

7. The permittee shall submit deviation (excursion) reports that identify any record which shows that the sulfur content of the natural gas exceeded 2 grains per standard cubic foot. These reports are due by the date described in Part I - General Terms and Conditions of this permit under section (A)(2).

8. The permittee shall submit deviation (excursion) reports that identify each time when this emissions unit was not in compliance with the requirements of condition II.3. above. These reports are due by the date described in Part I - General Terms and Conditions of this permit under section (A)(2).

9. In lieu of the excess emissions reports required under 40 CFR Part 60.334, the permittee shall submit excess emissions reports for emissions unit P001 in accordance with this permit.

10. This emissions unit is subject to the applicable provisions of Subpart Da and GG of the New Source Performance Standards (NSPS) as promulgated by the United States Environmental Protection Agency, 40 CFR Part 60. The application and enforcement of these standards are delegated to the Ohio EPA. The requirements of 40 CFR Part 60 are also federally enforceable.

Pursuant to 40 CFR Part 60.7, the permittee is hereby advised of the requirement to report the following at the appropriate times:

a. construction date (no later than 30 days after such date);

b. anticipated start-up date (not more than 60 days or less than 30 days prior to such date);

c. actual start-up date (within 15 days after such date); and,

d. date of performance testing (if required, at least 30 days prior to testing).

Reports are to be sent to:

Ohio Environmental Protection Agency
DAPC - Permit Management Unit
P. O. Box 163669
Columbus, Ohio 43216-3669

and

Ohio Environmental Protection Agency
Southeast District Office
Division of Air Pollution Control
2195 Front Street
Logan, Ohio 43138

V. Testing Requirements

1. The permittee shall conduct, or have conducted, emission testing for this emissions unit in accordance with the following requirements:

a. The emission testing shall be conducted within 60 days after achieving the maximum production rate at which the emissions unit will be operated, but not later than 180 days after initial startup of such emissions unit.

b. The emission testing shall be conducted to demonstrate compliance with the NO_x and CO outlet concentration, and the mass emissions limitations for NO_x,* CO, Formaldehyde, VOC and PM.

c. The following test method(s) shall be employed to demonstrate compliance with the above emissions limitations: for NO_x, Method 20 of 40 CFR Part 60, Appendix A; for PM, Method 5 of 40 CFR Part 60, Appendix A; for Formaldehyde, SW-846 Method 0011; for VOC Method 25 of 40 CFR Part 60, Appendix A; and for CO Method 10 of 40 CFR Part 60, Appendix A. Alternative U.S. EPA approved test methods may be used with prior approval from the Ohio EPA.

d. The testing shall be conducted while the emissions unit is operating at or near its maximum capacity with and without duct burner firing, unless otherwise specified or approved by Ohio EPA or local air agency.

e. Not later than 30 days prior to the proposed test date(s), the permittee shall submit an "Intent to Test" notification to the Ohio EPA, Southeast District Office. The "Intent to Test" notification shall describe in detail the proposed test methods and procedures, the emissions unit operating parameters, the time(s) and date(s) of the test(s), and the person(s) who will be conducting the test(s). Failure to submit such notification for review and approval prior to the test(s) may result in the Ohio EPA, Southeast District Office refusal to accept the results of the emission test(s).

f. Personnel from the Ohio EPA, Southeast District Office shall be permitted to witness the test(s), examine the testing equipment, and acquire data and information necessary to ensure that the operation of the emissions unit and the testing procedures provide a valid characterization of the emissions from the emissions unit and/or the performance of the control equipment.

g. A comprehensive written report on the results of the emissions test(s) shall be signed by the person or persons responsible for the tests and submitted to the Ohio EPA, Southeast District Office within 30 days following completion of the test(s). The permittee may request additional time for the submittal of the written report, where warranted, with prior approval from the Ohio EPA, Southeast District Office.

* Using the test methods and procedures required under 40 CFR Part 60.335.

2. Compliance with the allowable emission limitations in this permit shall be determined according to the following methods:

a. Emission Limitation

NO_x emissions shall not exceed 3.5 ppmvd at 15% Oxygen
24.7 lbs/hr without duct burner firing

32.3 lbs/hr with duct burner firing
157.5 tons per year, which includes 32.2 tons for startups and shutdowns

Applicable Compliance Method

Initial compliance with the allowable outlet concentration, and the lbs/hr emission limitations shall be demonstrated by the performance testing as described in condition V.1 and continual compliance with those limitations shall be demonstrated by the use of the CEM in condition III.3. based upon an hourly averaging period as allowed in 40 CFR Part 60. Compliance with the annual emission limitation shall be determined by the record keeping required in condition III. 1., 2., and 3. The annual emissions associated with start-up and shut-down shall be determined by the record keeping required in condition III. 9. using the lbs/ start-up and shut-down values in condition III.3.

b. Emission Limitation

PM emissions shall not exceed
19.0 lbs/hr without duct burner firing
28.0 lbs/hr with duct burner firing
103.5 tons per year

Applicable Compliance Method

Compliance with the lbs/hr emission limitations shall be demonstrated by the performance testing in condition V.1. Compliance with the annual emission limitation shall be determined by multiplying the hourly emission rate by the actual annual hours of operation and dividing by 2000 lbs/ton.

c. Emission Limitation

SO2 emissions shall not exceed
11.2 lbs/hr without duct burner firing
14.5 lbs/hr with duct burner firing
56.5 tons per year

Applicable Compliance Method

Compliance with the hourly emission limitation shall be determined by the record keeping required in condition III. 1., 2., and 8. If required, the permittee shall demonstrate compliance by emission testing in accordance with approved US EPA test methods. Compliance with the annual emission limitation shall be determined by multiplying the

hourly emission rate by the actual annual hours of operation and dividing by 2000 lbs/ton.

d. Emission Limitation

VOC emissions shall not exceed
3.0 lbs/hr without duct burner firing
19.6 lbs/hr with duct burner firing
63.1 tons per year, which includes 12.6 tons for startups and shutdowns

Applicable Compliance Method

Compliance with the lbs/hr limitations shall be demonstrated by the performance testing in condition V.1. Compliance with the annual emission limitation shall be determined by multiplying the hourly emission rate by the actual annual hours of operation and dividing by 2000 lbs/ton. The annual emissions associated with start-up and shut-down shall be determined by the record keeping required in condition III. 9. using the lbs/ start-up and shut-down values in condition III.3.

e. Emission Limitation

CO emissions shall not exceed
10 ppmvd at 15% Oxygen without duct burner firing
14 ppmvd at 15% Oxygen with duct burner firing
43.0 lbs/hr without duct burner firing
78.0 lbs/hr with duct burner firing
453.7 tons per year, which includes 186.6 tons for startups and shutdowns

Applicable Compliance Method

Initial compliance with the allowable outlet concentration, and the lbs/hr emission limitations shall be demonstrated by the performance testing as described in condition V.1.and continual compliance with those limitations shall be demonstrated by the use of the CEM in condition III.4. based upon an hourly averaging period as allowed in 40 CFR Part 60. Compliance with the annual emission limitation shall be determined by the record keeping required in condition III. 1., 2., and 4. The annual emissions associated with start-up and shut-down shall be determined by the record keeping required in condition III. 9. using the lbs/ start-up and shut-down values in condition III.3.

f. Emission Limitation

ammonia (NH3) emissions shall not exceed

26.6 lbs/hr without duct burner firing
34.6 lbs/hr with duct burner firing
134.5 tons per year

Applicable Compliance Method

Compliance with the lbs/hr emission limitation shall be demonstrated by multiplying the emission factor of 0.0136 pound of ammonia/MMBtu heat input (emission factor supplied by the permittee) by the maximum Btu rating. If required, the permittee shall demonstrate compliance by emission testing in accordance with approved US EPA test methods. Compliance with the annual emission limitation shall be determined by multiplying the hourly emission rate by the actual annual hours of operation and dividing by 2000 lbs/ton.

g. Emission Limitation

Formaldehyde emissions shall not exceed
0.8 lbs/hr without duct burner firing
0.82 lbs/hr with duct burner firing
3.6 tons per year

Applicable Compliance Method

Compliance with the lbs/hr emission limitations shall be demonstrated by the performance testing in condition V.1. Compliance with the annual emission limitation shall be determined by multiplying the hourly emission rate by the actual annual hours of operation and dividing by 2000 lbs/ton.

h. Emission Limitation

Sulfuric acid (H2SO4) emissions shall not exceed
1.7 lbs/hr without duct burner firing
2.2 lbs/hr with duct burner firing
8.6 tons per year

Applicable Compliance Method

Compliance with the lb/hr emission limitation shall be demonstrated by multiplying the emission factor of 0.0017 pound of sulfuric acid/MM Btu heat input (emission factor supplied by the permittee) by the maximum Btu rating. If required, the permittee shall demonstrate compliance by emission testing in accordance with approved US EPA test methods. Compliance with the annual emission limitation shall be determined by

multiplying the hourly emission rate by the actual annual hours of operation and dividing by 2000 lbs/ton.

i. Emission Limitation

Visible particulate emissions from any stack shall not exceed 10 percent opacity as a six-minute average.

Applicable Compliance Method

Compliance with the visible emissions limitation established by this permit shall be determined by Method 9, 40 CFR Part 60 Appendix A.

VI. Miscellaneous Requirements

1. In accordance with good engineering practices, the SCR unit on emissions unit P002 shall be installed, operated and maintained in accordance with the manufacturer's recommendations, with any modifications deemed necessary by the permittee. The permittee shall maintain on site a copy of the operation & maintenance manual, as provided by the manufacturer.

B. State Only Enforceable Section

I. Applicable Emissions Limitations and/or Control Requirements

1. The specific operations(s), property, and/or equipment which constitute this emissions unit are listed in the following table along with the applicable rules and/or requirements and with the applicable emissions limitations and/or control measures. Emissions from this unit shall not exceed the listed limitations, and the listed control measures shall be specified in narrative form following the table.

Operations, Property, and/or Equipment	Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
P002 - 170 MW GE 7FA natural gas-fired dry low NOx (DLN) combustion turbine with duct firing operating in combined cycle mode controlled by Selective Catalytic Reduction (SCR)	NONE	NONE

2. Additional Terms and Conditions

2.a NONE

II. Operational Restrictions

NONE

III. Monitoring and/or Recordkeeping Requirements

NONE

IV. Reporting Requirements

NONE

V. Testing Requirements

NONE

VI. Miscellaneous Requirements

NONE